

# Evaluation and Ranking of Geothermal Resources for Electrical Generation or Electrical Offset in Idaho, Montana, Oregon and Washington

by

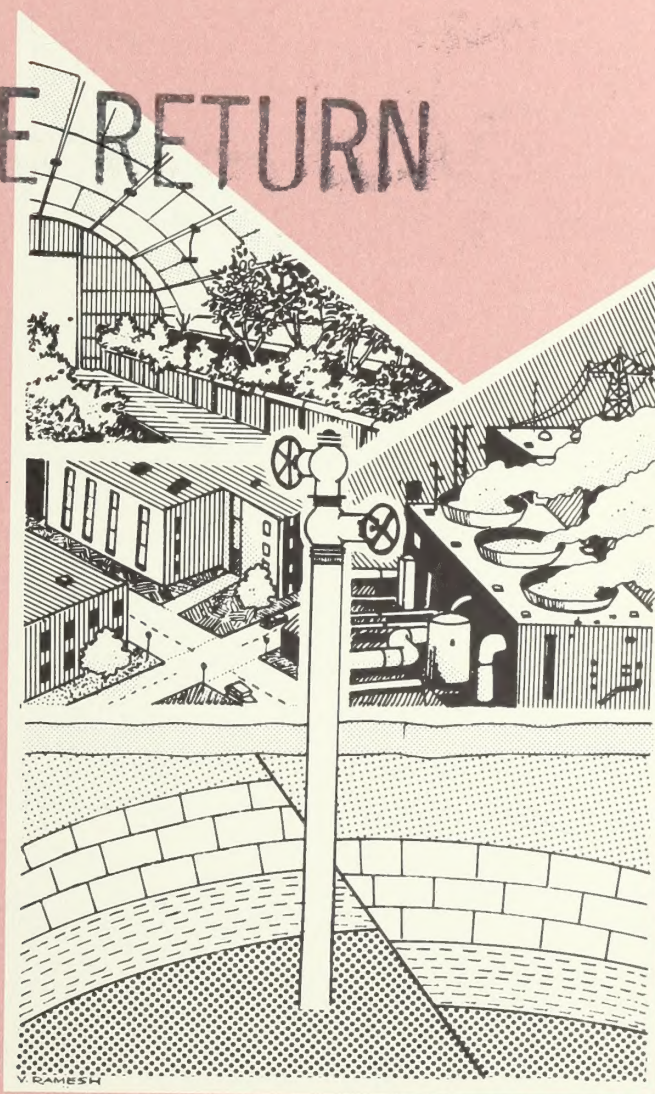
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## Volume II

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Evaluation and Ranking of Geothermal Resources  
for Electrical Generation or Electrical Offset  
in Idaho, Montana, Oregon and Washington

VOL. II

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Bonneville Power Administration  
U.S. Department of Energy  
Portland, OR

by

Washington State Energy Office  
in cooperation with:

Idaho Department of Water Resources  
Montana Department of Natural Resources & Conservation  
Oregon Department of Energy  
Oregon Department of Geology and Mineral Industries

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## CONVERSION FACTORS

### Metric/English Conversions

1 m <sup>3</sup>	=	35.3 ft <sup>3</sup> = 264 gals
1 meter	=	3.281 ft
1 kilogram	=	2.2 lb.
1 liter	=	0.264 gal. = 0.0353 ft <sup>3</sup>
1 liter/sec = .001 m <sup>3</sup> /sec	=	15.8 gpm
1 liter/min	=	.263 gpm
1 joule	=	0.000948 Btu
1°C	=	(°F - 32°) x 5/9
1 m <sup>2</sup>	=	10.76 ft <sup>2</sup>
1 kilometer	=	.62 miles
1 hectare	=	2.47 acres

### Nominal Fuel Heating Values

1 cubic foot natural gas	=	1,000 Btu
1 pound bituminous coal	=	12,500 Btu
1 gal. #2 fuel oil	=	1.42 x 10 <sup>5</sup> Btu
1 Therm	=	10 <sup>5</sup> Btu
1 barrel crude oil	=	5.6 million Btu
1 kWh	=	3,413 Btu
1 ton of refrigeration	=	12,000 Btu

### Energy Unit Conversion Chart (100% Efficiency)

British Thermal Units (Btu)	Cubic Feet Natural Gas (CF)	Kilowatt Hours Electricity (kWh)	Barrels of Oil (bbl)	Short Tons Bituminous Coal (T)	Tons of Refrigeration*
1	0.001	0.000293	---	---	---
1,000	1	0.293	0.00018	0.0004	.0833
3,413	3.41	1	0.00061	0.0014	.284
1 Million	1,000 (1 MCF)	293	0.18	0.04	83.3
3.41 Million	3,413	1,000 (1 MWh)	0.61	0.14	284
5.6 Million	5,600	1,640	1	0.22	466
25 Million	25,000	7,325	4.46	1	2,083
1 Quadrillion (Quad) (Q)	1 Trillion (1 TCF)	293 Billion	180 Million	40 Million	83.3 Billion

\*Defined as the heat of fusion of one ton of water, equal to 288,000 Btus.



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## APPENDIX 1

### Resource Assessment - Electrical Generation

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## KEY TO UNITS

Temperatures =  $^{\circ}\text{C}$

Area =  $\text{km}^2$

Thickness =  $\text{km}$

Volume =  $\text{km}^3$

Thermal Energy =  $\text{J} \times 10^{18}$

Electrical Energy =  $\text{MWe}$



HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - IDAHO

SITE	MINIMUM RESERVOIR TEMP	MOST LIKELY RESERVOIR TEMP	MAXIMUM RESERVOIR TEMP	MEAN RESERVOIR TEMP	VARIANCE	STANDARD DEVIATION
Krigbaum HS	89	97	120	102	43	7
White Licks HS	140	145	162	149	22	5
Guyer HS	71	88	128	96	143	12
Bonneville HS	87	94	145	109	167	13
Deer HS	138	139	143	140	1	1
Big Southern Butte				0	0	0
Barron's HS	91	95	123	103	51	7
Magic Reservoir	114	140	145	133	46	7
Worswick HS	81	90	98	90	12	3
Blackfoot Lava Field	200	230	270	233	206	14
Raft River	135	147	164	149	35	6
Sunbeam HS	76	94	111	94	51	7
Latty HS	55	102	137	98	282	17
Battle Creek HS	82	116	142	113	151	12
Ben Meek Well	73	97	125	98	113	11
Maple Grove HS	98	106	106	103	4	2
Squaw Creek HS	84	124	150	119	184	14
Island Park Caldera	200	230	270	233	206	14
Roystone HS	122	135	148	135	28	5
White Arrow	109	115	135	120	31	6
Riggins HS	82	98	120	100	61	8
Big Creek HS	145	159	184	163	65	8
Owl Creek HS	94	123	162	126	194	14
Sharkey HS	102	107	134	114	49	7
Rexburg Caldera	200	230	270	233	206	14
Indian Creek HS	93	121	142	119	101	10
Murphy HS	51	99	160	103	497	22
Boiling Springs	86	100	112	99	28	5
Cabarton HS	91	99	124	105	49	7
Vulcan HS	87	97	135	106	107	10
Cove Creek Crane Creek HS	151	163	173	162	20	4



HIGH TEMPERATURE GEOTHERMAL GENERATION SITES - IDAHO

SITE	MINIMUM RESERVOIR AREA	MOST LIKELY RESERVOIR AREA	MAXIMUM RESERVOIR AREA	MEAN RESERVOIR AREA	VARIANCE	STANDARD DEVIATION
Krigbaum HS	1.0	2.0	3.0	2.0	0.2	0.4
White Licks HS	1.0	2.0	3.0	2.0	0.2	0.4
Guyer HS	1.0	2.0	3.0	2.0	0.2	0.4
Bonneville HS	1.0	2.0	3.0	2.0	0.2	0.4
Deer HS	1.0	2.0	3.0	2.0	0.2	0.4
Big Southern Butte						
Barron's HS	1.0	2.0	3.0	0.0	0.0	0.0
Magic Reservior	1.0	2.0	3.0	2.0	0.2	0.4
Worswick HS	1.0	2.0	3.0	2.0	0.2	0.4
Blackfoot Lava Field	n/a	25.0	n/a	n/a	n/a	n/a
Raft River	5.0	15.0	30.0	16.7	26.4	5.1
Sunbeam HS	1.0	2.0	3.0	2.0	0.2	0.4
Latty HS	1.0	2.0	3.0	2.0	0.2	0.4
Battle Creek HS	1.0	2.0	3.0	2.0	0.2	0.4
Ben Meek Well	1.0	2.0	3.0	2.0	0.2	0.4
Maple Grove HS	1.0	2.0	3.0	2.0	0.2	0.4
Squaw Creek HS	1.0	2.0	3.0	2.0	0.2	0.4
Island Park Caldera	n/a	2100.0	n/a	n/a	n/a	n/a
Roystone HS	1.0	2.0	3.0	2.0	0.2	0.4
White Arrow	2.5	3.0	5.0	3.5	0.3	0.5
Riggins HS	1.0	2.0	3.0	2.0	0.2	0.4
Big Creek HS	1.0	2.0	3.0	2.0	0.2	0.4
Owl Creek HS	1.0	2.0	3.0	2.0	0.2	0.4
Sharkey HS	1.0	2.0	3.0	2.0	0.2	0.4
Rexburg Caldera	n/a	1800.0	n/a	n/a	n/a	n/a
Indian Creek HS	1.0	2.0	3.0	2.0	0.2	0.4
Murphy HS	1.0	2.0	3.0	2.0	0.2	0.4
Boiling Springs	1.0	2.0	3.0	2.0	0.2	0.4
Cabarton HS	1.0	2.0	3.0	2.0	0.2	0.4
Vulan HS	1.0	2.0	3.0	2.0	0.2	0.4
Cove Creek/Crane Creek HS	5.0	15.0	50.0	23.3	93.1	9.6



HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - IDAHO

	MINIMUM RESERVOIR THICKNESS	MOST LIKELY RESERVOIR THICKNESS	MAXIMUM RESERVOIR THICKNESS	MEAN RESERVOIR THICKNESS	VARIANCE	STANDARD DEVIATION
Krigbaum HS	1.0	1.5	2.5	1.7	0.1	0.3
White Licks HS	1.0	1.5	2.5	1.7	0.1	0.3
Guyer HS	1.0	1.5	2.5	1.7	0.1	0.3
Bonneville HS	1.0	1.5	2.5	1.7	0.1	0.3
Deer HS	1.0	1.5	2.5	1.7	0.1	0.3
Big Southern Butte				0.0	0.0	0.0
Barron's HS	1.0	1.5	2.5	1.7	0.1	0.3
Magic Reservoir	1.0	1.5	2.5	1.7	0.1	0.3
Worswick HS	1.0	1.5	2.5	1.7	0.1	0.3
Blackfoot Lava Field	n/a	n/a	n/a	n/a	n/a	n/a
Raft River	1.0	1.0	1.7	1.2	.0	0.2
Sunbeam HS	1.0	1.5	2.5	1.7	0.1	0.3
Latty HS	1.0	1.5	2.5	1.7	0.1	0.3
Battle Creek HS	0.5	1.7	2.5	1.6	0.2	0.4
Ben Meek Well	0.5	1.7	2.5	1.6	0.2	0.4
Maple Grove HS	1.0	1.5	2.5	1.7	0.1	0.3
Squaw Creek HS	0.5	1.7	2.5	1.6	0.2	0.4
Island Park Caldera	n/a	n/a	n/a	n/a	n/a	n/a
Roystone HS	1.0	1.5	2.5	1.7	0.1	0.3
White Arrow	1.0	1.5	2.5	1.7	0.1	0.3
Riggins HS	1.0	1.5	2.5	1.7	0.1	0.3
Big Creek HS	1.0	1.5	2.5	1.7	0.1	0.3
Owl Creek HS	1.0	1.5	2.5	1.7	0.1	0.3
Sharkey HS	1.0	1.5	2.5	1.7	0.1	0.3
Rexburg Caldera	n/a	n/a	n/a	n/a	n/a	n/a
Indian Creek	1.0	1.5	2.5	1.7	0.1	0.3
Murphy HS	1.0	1.5	2.5	1.7	0.1	0.3
Boiling Springs	1.0	1.5	2.5	1.7	0.1	0.3
Cabarton HS	1.0	1.5	2.5	1.7	0.1	0.3
Vulcan HS	1.0	1.5	2.5	1.7	0.1	0.3
Cove Creek/Crane Creek	1.0	1.5	2.5	1.7	0.1	0.3



HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - IDAHO

	RESERVOIR VOLUME	VARIANCE	STANDARD DEVIATION	MEAN SURFACE TEMP	WA/QR	THERMAL UTILIZATION FACTOR
Krigbaum HS	3.3	0.9	0.9	4.4	0.029	0.023
White Licks HS	3.3	0.9	0.9	4.4	0.044	0.048
Guyer HS	3.3	0.9	0.9	6.2	0.027	0.017
Bonneville HS	3.3	0.9	0.9	4.4	0.032	0.029
Deer HS	3.3	0.9	0.9	5.0	0.042	0.045
Big Southern Butte	100.00	0.0	0.0			
Barron's HS	3.3	0.9	0.9	6.1	0.029	0.024
Magic Reservoir	3.3	0.9	0.9	6.1	0.040	0.041
Worswick HS	3.3	0.9	0.9	3.3	0.024	0.012
Blackfoot Lava Field	133.0	1489.0	39.0	8.2	0.064	0.430
Raft River	20.6	48.4	7.0	7.2	0.044	0.048
Sunbeam HS	3.3	0.9	0.9	3.3	0.026	0.016
Latty HS	3.3	0.9	0.9	10.0	0.028	0.019
Battle Creek HS	3.1	1.1	1.1	7.8	0.033	0.031
Ben Meek Well	3.1	1.1	1.1	7.8	0.027	0.019
Maple Grove	3.3	0.9	0.9	7.8	0.030	0.024
Squaw Creek HS	3.1	1.1	1.1	7.8	0.035	0.034
Island Park Caldera	14150.0	10800000.0	3296.0	5.0	0.064	0.430
Roystone HS	3.3	0.9	0.9	10.6	0.040	0.041
White Arrow	5.8	2.0	1.4	10.0	0.035	0.035
Riggins HS	3.3	0.9	0.9	12.2	0.028	0.021
Bg Creek HS	3.3	0.9	0.9	6.7	0.048	0.380
Owl Creek HS	3.3	0.9	0.9	6.7	0.037	0.038
Sharkey HS	3.3	0.9	0.9	6.7	0.033	0.031
Rexburg Caldera	10500.0	7875000.0	2806.0	5.9	0.064	0.430
Indian Creek HS	3.3	0.9	0.9	11.1	0.035	0.034
Murphy HS	3.3	0.9	0.9	11.1	0.030	0.024
Boiling Springs	3.3	0.9	0.9	4.4	0.029	0.020
Cabarton HS	3.3	0.9	0.9	5.0	0.030	0.025
Vulcan HS	3.3	0.9	0.9	4.4	0.031	0.026
Cove Creek/Crane Creek HS	38.9	320.5	17.9	10.4	0.047	0.380



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - IDAHO

	RESERVOIR THERMAL ENERGY	VARIANCE	STANDARD DEVIATION	WELLHEAD THERMAL ENERGY	WELLHEAD AVAIL WORK
Krigbaum HS	8.78E+17	6.40E+34	2.5E+17	2.20E+17	2.5E+16
White Licks HS	1.30E+18	1.34E+35	3.7E+17	3.25E+17	5.7E+16
Guyer HS	8.05E+17	6.31E+34	2.5E+17	2.01E+17	2.2E+16
Bonneville HS	9.38E+17	8.34E+34	2.9E+17	2.35+17	3.0E+16
Deer HS	1.22E+18	1.15E+35	3.4E+17	3.04E+17	5.1E+16
Big Southern Butte	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Barron's HS	8.72E+17	6.38E+34	2.5E+17	2.18E+17	2.5E+16
Magic Reservoir	1.14E+18	1.06E+35	3.3E+17	2.86E+17	4.6E+16
Worswick	7.77E+17	4.83E+34	2.2E+17	1.94E+17	1.9E+16
Blackfoot Lava Field	2.40E+20	n/a	n/a	6.00E+19	1.5E+19
Raft River	7.85E+18	7.19E+36	2.7E+18	1.96E+18	3.5E+17
Sunbeam HS	8.13E+17	5.61E+34	2.4E+17	2.03E+17	2.1E+16
Latty HS	7.92E+17	7.36E+34	2.7E+17	1.98E+17	2.2E+16
Battle Creek HS	8.93E+17	1.02E+35	3.2E+17	2.23E+17	2.9E+16
Ben Meek Well	7.66E+17	7.55E+34	2.7E+17	1.91E+17	2.1E+16
Maple Grove HS	8.60E+17	5.81E+34	2.4E+17	2.15E+17	2.6E+16
Squaw Creek HS	9.44E+17	1.16E+35	3.4E+17	2.36E+17	3.3E+16
Island Park Caldera	1.69E+22	n/a	n/a	4.23E+21	1.1E+21
Roystone HS	1.12E+18	1.00E+35	3.2E+17	2.80E+17	4.5E+16
White Arrow	1.73E+18	1.86E+35	4.3E+17	4.32E+17	6.0E+16
Riggins HS	7.90E+17	5.41E+34	2.3E+17	1.98E+17	2.2E+16
Big Creek HS	1.40E+18	1.60E+35	4.0E+17	3.51E+17	6.7E+16
Owl Creek	1.08E+18	1.08E+35	3.3E+17	2.69E+17	4.0E+16
Sharkey HS	9.69E+17	7.76E+34	2.8E+17	2.42E+17	3.2E+16
Rexburg Caldera	8.40E+21	n/a	n/a	2.10E+21	5.4E+20
Indian Creek HS	9.68E+17	8.20E+34	2.9E+17	2.42E+17	3.4E+16
Murphy HS	8.30E+17	9.73E+34	3.1E+17	2.08E+17	2.5E+16
Boiling Springs	8.54E+17	5.95E+34	2.4E+17	2.14E+17	2.5E+16
Cabarton HS	8.97E+17	6.72E+34	2.6E+17	2.24E+17	2.7E+16
Vulcan HS	9.17E+17	7.51E+34	2.7E+17	2.29E+17	2.8E+16
Cove Creek/Crane Creek HS	1.60E+19	5.42E+37	7.4E+18	3.99E+18	7.5E+17



HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - IDAHO

	ELECTRICAL ENERGY	BEST RESERVOIR THERMAL ENERGY	BEST WA/QR	BEST THERMAL UTIL FACTOR	BEST ELECTRICAL ENERGY	REMARKS
Krigbaum HS	1	7.50E+17	0.027	0.018	0	
White Licks HS	3	1.14E+18	0.043	0.047	2	
Guyer HS	0	6.63E+17	0.024	0.011	0	
Bonneville HS	1	7.26E+17	0.026	0.015	0	
Deer HS	2	1.09E+18	0.041	0.044	2	
Big Southern Butte	0	0				Insufficient data
Barron's HS	1	7.20E+17	0.026	0.017	0	
Magic Reservoir	2	1.08E+18	0.042	0.045	2	
Worswick HS	0	7.02E+17	0.024	0.012	0	
Blackfoot Lava Field	6974	5.90E+19	0.064	0.430	1715	
Raft River	18	5.66E+18	0.043	0.047	12	
Sunbeam HS	0	7.35E+17	0.026	0.016	0	
Latty HS	0	7.45E+17	0.029	0. -023	1	
Battle Creek HS	1	9.93E+17	0.034	0.033	1	
Ben Meek Well	0	8.19E+17	0.027	0.018	0	
Maple Grove	1	7.95E+17	0.0031	0.0026	1	
Squaw Creek HS	1	1.07E+18	0.037	0.037	2	
Island Park Caldera	491117	5.45E+21	0.064	0.430	158378	
Roystone HS	2	1.01E+18	0.040	0.041	2	
White Arrow	2	1.28E+18	0.034	0.032	1	
Riggings HS	0	6.95E+17	0.027	0.019	0	
Big Creek HS	27	1.23E+18	0.047	0.380	23	
Owl Creek	2	9.42E+17	0.036	0.036	1	
Sharkey HS	1	8.12E+17	0.031	0.027	1	
Rexburg Caldera	244106	3.54E+21	0.064	0.430	102873	
Indian Creek HS	1	8.90E+17	0.036	0.035	1	
Murphy HS	1	7.12E+17	0.028	0.024	1	
Boiling Springs	1	7.74E+17	0.029	0.021	0	
Cabarton HS	1	7.61E+17	0.028	0.020	0	
Vulcan HS	1	7.50E+17	0.027	0.018	0	
Cove Creek/Crane Creek HS	301	9.27E+18	0.048	0.380	179	



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - MONTANA

SITE	MINIMUM RESERVOIR TEMP	MOST LIKELY RESERVOIR TEMP	MAXIMUM RESERVOIR TEMP	MEAN RESERVOIR TEMP	VARIANCE	STANDARD DEVIATION
Jackson	73	148	150	124	321	18
Gregson (Fairmont)	73	126	128	109	162	13
Boulder	130	136	142	136	6	2
Broadwater	85	98	105	96	17	4
Ennis	108	135	145	129	61	8
Norris	87	103	130	107	79	9
Silver Star	116	135	143	131	32	6
Marysville	103	117	145	122	76	9



HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - MONTANA

	MINIMUM RESERVOIR AREA	MOST LIKELY RESERVOIR AREA	MAXIMUM RESERVOIR AREA	MEAN RESERVOIR AREA	VARIANCE	STANDARD DEVIATION
Jackson	1.0	2.0	3.0	2.0	0.2	0.4
Gregson (Fairmont)	1.0	2.0	3.0	2.0	0.2	0.4
Boulder	1.0	2.0	3.0	2.0	0.2	0.4
Broadwater	1.0	2.0	3.0	2.0	0.2	0.4
Ennis	1.0	2.0	3.0	2.0	0.2	0.4
Norris	1.0	2.0	3.0	2.0	0.2	0.4
Silver Star	1.0	2.0	3.0	2.0	0.2	0.4
Marysville	6.0	6.0	16.0	9.3	5.6	2.4



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC SITES - MONTANA

	MINIMUM RESERVOIR THICKNESS	MOST LIKELY RESERVOIR THICKNESS	MAXIMUM RESERVOIR THICKNESS	MEAN RESERVOIR THICKNESS	VARIANCE	STANDARD DEVIATION
Jackson	1.0	1.5	2.5	1.7	0.1	0.3
Gregson (Fairmont)	1.0	1.5	2.5	1.7	0.1	0.3
Boulder	1.0	1.5	2.5	1.7	0.1	0.3
Broadwater	1.0	1.5	2.5	1.7	0.1	0.3
Ennis	1.0	1.5	2.5	1.7	0.1	0.3
Norris	1.0	1.5	2.5	1.7	0.1	0.3
Silver Star	1.0	1.5	2.5	1.7	0.1	0.3
Marysville	1.0	1.5	2.0	1.5	.0	0.2



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC SITES - MONTANA

	RESERVOIR VOL	VARIANCE	STANDARD DEVIATION	MEAN SURFACE TEMP	WA/QR	THERMAL UTILIZATION FACTOR
Jackson	3.3	0.9	0.9	4.1	0.036	0.036
Gregson	3.3	0.9	0.9	5.2	0.032	0.029
Boulder	3.3	0.9	0.9	5.4	0.040	0.043
Broadwater	3.3	0.9	0.9	6.1	0.027	0.017
Ennis	3.3	0.9	0.9	6.0	0.038	0.039
Norris	3.3	0.9	0.9	5.9	0.031	0.027
Silver Star	3.3	0.9	0.9	6.1	0.039	0.040
Marysville	14.0	16.4	4.0	4.8	0.036	0.036



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - MONTANA

	RESERVOIR THERMAL ENERGY	VARIANCE	STANDARD DEVIATION	WELLHEAD THERMAL ENERGY	WELLHEAD AVAILABLE WORK
Jackson	1.08E+18	1.19E+35	3.4E+17	2.69E+17	3.9E+16
Gregson (Fairmont)	9.34E+17	8.23E+34	2.9E+17	2.34E+17	3.0E+16
Boulder	1.18E+18	1.08E+35	3.3E+17	2.94E+17	4.7E+16
Broadwater	8.09E+17	5.26E+34	2.3E+17	2.02E+17	2.2E+16
Ennis	1.11E+18	1.02E+35	3.2E+17	2.78E+17	4.2E+16
Norris	9.07E+17	7.11E+34	2.7E+17	2.27E+172	2.8E+16
Silver Star	1.13E+18	1.02E+35	3.2E+17	2.82E+17	4.4E+16
Marysville	4.42E+18	1.75E+36	1.3E+18	1.10E+18	1.6E+17



HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - MONTANA

	ELECTRICAL ENERGY	BEST RESERVOIR THERMAL ENERGY	BEST ELECTRICAL ENERGY	REMARKS
Jackson	1	1.17E+17	2	
Gregson (Fairmont)	1	9.78E+17	1	
Boulder	2	1.06E+18	2	
Broadwater	0	7.44E+17	0	
Ennis	2	1.04E+18	2	
Norris	1	7.87E+17	1	
Silver Star	2	1.04E+18	2	
Marysville	6	2.73E+18	4	



HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - OREGON

	MINIMUM RESERVOIR TEMP	MOST LIKELY RESERVOIR TEMP	MAXIMUM RESERVOIR TEMP	MEAN RESERVOIR TEMP	VARIANCE	STANDARD DEVIATION
Kropp HS	79	100	109	96	40	6
Austin HS	87	90	126	101	79	9
Mt. Hood	90	120	192	134	458	21
Bearwallow Butte	200	230	270	233	206	14
China Hat-East Butte				0	0	0
Frederick Butte				0	0	0
Melvin-Three Creek Buttes	200	230	270	233	206	14
Newberry Volcano	230	265	280	258	110	10
Quartz Mountain				0	0	0
Shukash Basin				0	0	0
Umpqua HS	108	108	135	117	41	6
Blue Mountain HS	99	99	126	108	41	6
Weberg HS	92	92	126	103	64	8
Alvord HS	148	164	231	181	323	18
Borax Lake HS	165	176	231	191	208	14
Crane HS	99	124	127	117	39	6
Diamond Craters				0	0	0
Mickey HS	180	227	240	216	166	13
O.J. Thomas Well	72	102	131	102	145	12
Trout Creek Area	140	143	180	154	83	9
Mt. McLoughlin Area	155	190	210	185	129	11
Rustler Peak				0	0	0
Cappy-Burn Butte Area	200	230	270	233	206	14
Crater Lake Area	155	190	210	185	129	11
Klamath Falls Area	150	180	185	172	60	8
Klamath Hills Area	150	180	200	177	106	10
Olene Gap HS	150	180	196	175	91	10
Barry Ranch HS	127	139	152	139	26	5
Cougar Peak Area				0	0	0
Crump Geyser	152	173	208	178	133	12



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - OREGON

	MINIMUM RESERVOIR AREA	MOST LIKELY RESERVOIR AREA	MAXIMUM RESERVOIR AREA	MEAN RESERVOIR AREA	VARIANCE	STANDARD DEVIATION
Kropp HS	1.0	2.0	3.0	2.0	0.2	0.4
Austin HS	1.0	2.0	3.0	2.0	0.2	0.4
Mt. Hood	9.0	30.0	95.0	44.7	335.1	18.3
Bearhallow Butte		8.0				
China Hat-East Butte				0.0	0.0	0.0
Frederick Butte		32.0				
Melvin-Three Creek Buttes		10.0				
Newberry Volcano	39.0	45.0	134.0	72.7	471.7	21.7
Quartz Mountain				0.0	0.0	0.0
Shukash Basin				0.0	0.0	0.0
Umpqua HS	1.0	2.0	3.0	2.0	0.2	0.4
Blue Mountain HS	1.0	2.0	3.0	2.0	0.2	0.4
Weberg HS	1.0	2.0	3.0	2.0	0.2	0.4
Alvord HS	1.0	2.0	6.0	3.0	1.2	1.1
Borax Lake HS	1.0	4.0	10.0	5.0	3.5	1.9
Crane HS	1.0	2.0	3.0	2.0	0.2	0.4
Diamond Craters				0.0	0.0	0.0
Mickey HS	1.0	4.0	18.0	7.7	13.7	3.7
O.J. Thomas Well	1.0	2.0	3.0	2.0	0.2	0.4
Trout Creek Area	1.0	2.0	3.0	2.0	0.2	0.4
Mt. McLoughlin Area	70.0	1050.0	1880.0	1000.0	136816.7	369.9
Rustler Peak				0.0	0.0	0.0
Cappy-Burn Butte Area		8.0			*****	1102.9
Crater Lake Area	750.0	2630.0	6077.0	3152.3		
Klamath Falls Area	0.1	21.0	34.0	18.4	48.8	7.0
Klamath Hills Area	0.2	17.0	38.0	18.4	59.9	7.7
Olene Gap HS	0.1	1.2	11.5	4.3	6.6	2.6
Barry Ranch HS	0.3	0.8	18.0	6.4	16.9	4.1
Cougar Peak Area				0.0	0.0	0.0
Crump Geyser	1.0	4.0	8.0	4.3	2.1	1.4



HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - OREGON

	MINIMUM RESERVOIR THICKNESS	MOST LIKELY RESERVOIR THICKNESS	MAXIMUM RESERVOIR THICKNESS	MEAN RESERVOIR THICKNESS	VARIANCE	STANDARD DEVIATION
Kropp HS	1.0	1.5	2.5	1.7	0.1	0.3
Austin HS	1.0	1.5	2.5	1.7	0.1	0.3
Mt. Hood	0.2	0.4	1.6	0.7	0.1	0.3
Bearhallow Butte						
China Hat-East Butte				0.0	0.0	0.0
Frederick Butte						
Melvin-Three Creek Buttes						
Newberry Volcano	1.0	1.5	2.0	1.5	.0	0.2
Quartz Mountain				0.0	0.0	0.0
Shukash Basin				0.0	0.0	0.0
Umpqua HS	1.0	1.5	2.5	1.7	0.1	0.3
Blue Mountain HS	1.0	1.5	2.5	1.7	0.1	0.3
Weberg HS	1.0	1.5	2.5	1.7	0.1	0.3
Alvord HS	0.5	1.7	2.5	1.6	0.2	0.4
Borax Lake HS	0.5	1.7	2.5	1.6	0.2	0.4
Crane HS	0.5	1.7	2.5	1.6	0.2	0.4
Diamond Craters				0.0	0.0	0.0
Mickey HS	0.5	1.7	2.5	1.6	0.2	0.4
O.J. Thomas Well	0.5	1.7	2.5	1.6	0.2	0.4
Trout Creek Area	0.5	1.7	2.5	1.6	0.2	0.4
Mt. McLoughlin Area	0.3	1.3	1.7	1.1	0.1	0.3
Rustler Peak				0.0	0.0	0.0
Cappy-Burn Butte Area						
Crater Lake Area	0.3	1.3	1.7	1.1	0.1	0.3
Klamath Falls Area	0.5	1.7	2.5	1.6	0.2	0.4
Klamath Hills Area	0.5	1.7	2.5	1.6	0.2	0.4
Olene Gap HS	0.5	1.7	2.5	1.6	0.2	0.4
Barry Ranch HS	0.5	1.7	2.5	1.6	0.2	0.4
Cougar Peak Area				0.0	0.0	0.0
Crump Geyser	0.5	1.7	2.5	1.6	0.2	0.4



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - OREGON

	RESERVOIR VOLUME	VARIANCE	STANDARD DEVIATION	MEAN SURFACE TEMP	WA/QR	THERMAL UTILIZATION FACTOR
Kropp HS	3.3	0.9	0.9	7.0	0.028	0.020
Austin HS	3.3	0.9	0.9	9.9	0.028	0.022
Mt. Hood	32.8	402.8	20.1	4.9	0.039	0.042
Bearhallow Butte	43.0	172.0	13.0	3.5	0.064	0.430
China Hat-East Butte	0.0	0.0	0.0			
Frederick Butte	125.0	2713.0	52.0	0.0		
Melvin-Three Creek Buttes	55.0	263.0	16.2	3.5	0.064	0.430
Newberry Volcano	109.0	1301.0	36.1	0.0	0.069	0.430
Quartz Mountain	0.0	0.0	0.0			
Shukash Basin	0.0	0.0	0.0			
Umpqua HS	3.3	0.9	0.9	9.9	0.035	0.033
Blue Mountain HS	3.3	0.9	0.9	8.0	0.032	0.028
Heberg HS	3.3	0.9	0.9	6.9	0.030	0.024
Alvord HS	4.7	4.6	2.1	8.3	0.052	0.400
Borax Lake HS	7.8	13.4	3.7	8.3	0.055	0.390
Crane HS	3.1	1.1	1.1	5.4	0.034	0.033
Diamond Craters	0.0	0.0	0.0			
Mickey HS	12.0	45.9	6.8	8.3	0.063	0.410
O.J. Thomas Well	3.1	1.1	1.1	5.4	0.029	0.023
Trout Creek Area	3.1	1.1	1.1	8.3	0.046	0.350
Mt. McLoughlin Area	1066.7	260033.0	509.9	10.0	0.053	0.390
Rustler Peak	0.0	0.0	0.0			
Cappy-Burn Butte Area	47.0	156.0	12.0	3.5	0.064	0.430
Crater Lake Area	3362.5	2408049.3	1551.8	5.0	0.053	0.390
Klamath Falls Area	28.8	184.9	13.6	8.8	0.050	0.400
Klamath Hills Area	28.8	214.2	14.6	8.8	0.051	0.400
Olene Gap HS	6.7	20.4	4.5	8.8	0.051	0.400
Barry Ranch HS	10.0	51.3	7.2	7.8	0.041	0.044
Cougar Peak Area	0.0	0.0	0.0			
Crump Geyser	6.8	8.6	2.9	9.4	0.051	0.400



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - OREGON

	RESERVOIR THERMAL ENERGY	VARIANCE	STANDARD DEVIATION	WELLHEAD THERMAL ENERGY	WELLHEAD AVAIL WORK	ELECT ENERGY
Kropp HS	8.01E+17	5.36E+34	2.3E+17	2.00E+17	2.2E+16	0
Austin HS	8.20E+17	5.94E+34	2.4E+17	2.05+17	2.3E+16	1
Mt. Hood	1.14E+19	5.39E+37	7.3E+18	2.85E+18	4.5E+17	20
Bearhallow Butte	4.10E+19			1.03E+19	2.6E+18	1191
China Hat-East Butte	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.0E+00	0
Frederick Butte	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.0E+00	0
Melvin-Three Creek Buttes	7.60E+19			1.90E+19	4.9E+18	2209
Newberry Volcano	7.60E+19	6.44E+38	2.5E+19	1.90E+19	5.2E+18	2382
Quartz Mountain	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.0E+00	0
Shukash Basin	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.0E+00	0
Umpqua HS	9.64E+17	7.61E+34	2.8E+17	2.41E+17	3.4E+16	1
Blue Mountain HS	9.00E+17	6.68E+34	2.6E+17	2.25E+17	2.9E+16	1
Weberg HS	8.68E+17	6.45E+34	2.5E+17	2.17E+17	2.6E+16	1
Alvord HS	2.19E+18	1.06E+36	1.0E+18	5.48E+17	1.1E+17	48
Borax Lake HS	3.86E+18	3.36E+36	1.8E+18	9.64E+17	2.1E+17	87
Crane HS	9.41E+17	1.04E+35	3.2E+17	2.35+17	3.2E+16	1
Diamond Craters	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.0E+00	0
Mickey HS	6.72E+18	1.46E+37	3.8E+18	1.68E+18	4.2E+17	183
O.J. Thomas Well	8.14E+17	8.67E+34	2.9E+17	2.04E+17	2.4E+16	1
Trout Creek Area	1.24E+18	1.80E+35	4.2E+17	3.09E+17	5.7E+16	21
Mt. McLoughlin Area	5.04E+20	5.94E+40	2.4E+20	1.26E+20	2.7E+19	11001
Rustler Peak	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.0E+00	0
Cappy-Burn Butte Area	1.30E+19			3.25E+18	8.3E+17	378
Crater Lake Area	1.63E+21	5.82E+41	7.6E+20	4.09E+20	8.7E+19	35669
Klamath Falls Area	1.27E+19	3.62E+37	6.0E+18	3.16E+18	6.3E+17	267
Klamath Hills Area	1.31E+19	4.48E+37	6.7E+18	3.26E+18	6.7E+17	281
Olene Gap HS	2.99E+18	4.17E+36	2.0E+18	7.48E+17	1.5E+17	64
Barry Ranch HS	3.54E+18	6.49E+36	2.5E+18	8.86E+17	1.5E+17	7
Cougar Peak Area	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.0E+00	0
Crump Geyser	3.08E+18	1.82E+36	1.3E+18	7.71E+17	1.6E+17	66



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - OREGON

	BEST RESERVOIR THERMAL ENERGY	BEST W/A/QR	BEST THERMAL UTIL FACTOR	BEST ELECT ENERGY	REMARKS
Kropp HS	7.53E+17	0.028	0.021	0	Default values for A and th too large.
Austin HS	6.49E+17	0.023	0.012	0	
Mt. Hood	3.73E+18	0.035	0.035	5	
Bearwallow Butte	2.10E+19	0.064	0.430	610	A blind resource.
China Hat-East Butte	0 (?)				Intrusive cooled to ambient (?)
Frederick Butte	4.00E+18			0	Intrusive cooled to ambient (?)
Melvin-Three Creek Buttes	3.80E+19	0.064	0.430	1104	A blind resource.
Newberry Volcano	4.83E+19	0.071	0.430	1557	
Quartz Mountain	0 (?)			0	Intrusive cooled to ambient (?)
Shukash Basin	0.00E+00			0	No significant high level resource.
Umpqua HS	7.95E+17	0.032	0.028	1	
Blue Mountain HS	7.37E+17	0.028	0.020	0	
Heberg HS	6.89E+17	0.026	0.014	0	
Alvord HS	1.43E+18	0.048	0.390	28	
Borax Lake HS	3.08E+18	0.051	0.400	66	
Crane HS	1.09E+18	0.037	0.037	2	
Diamond Craters	0 (?)				Insufficient data.
Mickey HS	4.02E+18	0.063	0.410	110	
O.J. Thomas Well	8.87E+17	0.029	0.023	1	
Trout Creek Area	1.24E+18	0.043	0.046	3	
Mt. McLoughlin Area	6.38E+20	0.055	0.380	14078	Area inc. 290 sq. kn. of wilderness area.
Rustler Peak	0 (?)			0	Insufficient data.
Cappy-Burn Butte Area	1.30E+19	0.064	0.430	378	A blind resource.
Crater Lake Area	1.64E+21	0.055	0.380	36241	Area inc. 720 sq.km. of Crater Lk. Park.
Klamath Falls Area	1.65E+19	0.052	0.400	362	
Klamath Hills Area	1.34E+19	0.052	0.400	293	
Olene Gap HS	9.43E+17	0.052	0.400	21	
Barry Ranch	4.82E+17	0.041	0.044	1HS	
Cougar Peak Area	0 (?)			0	Unlikely that a resource is present.
Crump Geyser	3.00E+18	0.050	0.400	63	



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - OREGON

	MINIMUM RESERVOIR TEMP	MOST LIKELY RESERVOIR TEMP	MAXIMUM RESERVOIR TEMP	MEAN RESERVOIR TEMP	VARIANCE	STANDARD DEVIATION
Devils Garden Area						
Fischer HS	123	123	170	0	0	0
Four Craters Lava Field				139	123	11
Glass Buttes	200	230	270	0	0	0
Hallinan HS	105	136	179	233	206	14
Lakeview Area	133	143	157	140	230	15
Squaw Ridge Field				144	24	5
Summer Lake HS	110	127	189	0	0	0
Wart Peak Caldera	200	230	270	142	288	17
Belknap HS	82	108	148	233	206	14
Bigelow HS	85	89	117	113	184	14
Foley HS	82	106	111	97	51	7
McCredie HS	74	96	124	100	40	6
Wall Creek HS	68	92	120	98	105	10
Generic HC Fault System	155	190	210	93	113	11
Beulah HS	85	85	169	185	129	11
Jackies Butte Field				113	392	20
Jordan Craters Field				0	0	0
Little Valley HS	98	118	126	0	0	0
Luce HS	96	116	143	114	35	6
McDermitt Area	76	90	106	118	93	10
Mitchell Butte HS	72	90	118	91	38	6
Neal HS	173	181	210	93	90	9
Vale HS	151	152	161	188	63	8
Breitenbush HS	99	102	127	155	5	2
Medical HS	66	97	125	109	39	6
Kahneeta HS	104	147	162	96	145	12
				138	151	12



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - OREGON

	MINIMUM RESERVOIR AREA	MOST LIKELY RESERVOIR AREA	MAXIMUM RESERVOIR AREA	MEAN RESERVOIR AREA	VARIANCE	STANDARD DEVIATION
Devils Garden Area						
Fischer HS	1.0	2.0	3.0	0.0	0.0	0.0
Four Craters Lava Field						
Glass Buttes	3.0	21.0	63.0	29.0	158.0	12.6
Hallinan HS	1.	2.0	3.0	2.0	0.2	0.4
Lakeview Area	0.4	6.0	20.0	8.8	17.0	4.1
Squaw Ridge Field						
Summer Lake HS	1.0	5.0	11.0	0.0	0.0	0.0
Wart Peak Caldera		40.0		5.7	4.2	2.1
Belknap HS	1.0	2.0	3.0	2.0	0.2	0.4
Bigelow HS	1.0	2.0	3.0	2.0	0.2	0.4
Foley HS	1.0	2.0	3.0	2.0	0.2	0.4
McCredie HS	1.0	2.0	3.0	2.0	0.2	0.4
Wall Creek HS	1.0	2.0	3.0	2.0	0.2	0.4
Generic HC Fault System	1.0	2.0	3.0	2.0	0.2	0.4
Beulah HS	1.0	2.0	3.0	2.0	0.2	0.4
Jackies Butte Field				0.0	0.0	0.0
Jordan Craters Field				0.0	0.0	0.0
Little Valley HS	1.0	2.0	3.0	2.0	0.2	0.4
Luce HS	1.0	2.0	3.0	2.0	0.2	0.4
McDermitt Area	1.0	2.0	3.0	2.0	0.2	0.4
Mitchell Butte HS	1.0	2.0	3.0	2.0	0.2	0.4
Heal HS	1.0	2.0	3.0	2.0	0.2	0.4
Vale HS	6.6	41.0	150.0	65.9	934.1	30.6
Breitenbush HS	1.0	2.0	3.0	2.0	0.2	0.4
Medical HS	1.0	2.0	3.0	2.0	0.2	0.4
Kahneeta HS	1.0	2.0	3.0	2.0	0.2	0.4



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - OREGON

	MINIMUM RESERVOIR THICKNESS	MOST LIKELY RESERVOIR THICKNESS	MAXIMUM RESERVOIR THICKNESS	MEAN RESERVOIR THICKNESS	VARIANCE	STANDARD DEVIATION
Devils Garden Area						
Fischer HS	0.5	1.7	2.5	0.0	0.0	0.0
Four Craters Lava Field						
Glass Buttes	.0	0.8	1.5	0.0	0.2	0.4
Hallinan HS	0.5	1.7	2.5	0.8	0.0	0.0
Lakeview Area	0.5	1.7	2.5	1.6	0.1	0.3
Squaw Ridge Field				1.6	0.2	0.4
Summer Lake HS				1.6	0.2	0.4
Wart Peak Caldera	0.5	1.7	2.5	0.0	0.0	0.0
Belknap HS	1.0	1.5	2.5	1.6	0.2	0.4
Bigelow HS	1.0	1.5	2.5	1.7	0.1	0.3
Foley HS	1.0	1.5	2.5	1.7	0.1	0.3
McCredie HS	1.0	1.5	2.5	1.7	0.1	0.3
Wall Creek HS	1.0	1.5	2.5	1.7	0.1	0.3
Generic HC Fault System	0.3	1.3	1.7	1.1	0.1	0.3
Beulah HS	0.5	1.7	2.5	1.6	0.2	0.4
Jackies Butte Field				0.0	0.0	0.0
Jordan Craters Field				0.0	0.0	0.0
Little Valley HS	0.5	1.7	2.5	1.6	0.2	0.4
Luce HS	0.5	1.7	2.5	1.6	0.2	0.4
McDermitt Area	0.5	1.7	2.5	1.6	0.2	0.4
Mitchell Butte HS	0.5	1.7	2.5	1.6	0.2	0.4
Heal HS	0.5	1.7	2.5	1.6	0.2	0.4
Vale HS	0.4	0.5	0.7	0.5	.0	0.1
Breitenbush HS	1.0	1.5	2.5	1.7	0.1	0.3
Medical HS	1.0	1.5	2.5	1.7	0.1	0.3
Kahneeta HS	1.0	1.5	2.5	1.7	0.1	0.3



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - OREGON

	RESERVOIR VOLUME	VARIANCE	STANDARD DEVIATION	MEAN SURFACE TEMP	W/A/QR	THERMAL UTIL FACTOR
Devils Garden Area	0.0	0.0	0.0			
Fischer HS	3.1	1.1	1.1	9.4	0.041	0.048
Four Craters Lava Field	0.0	0.0	0.0			
Glass Buttes	21.8	182.1	13.5	5.4	0.064	0.430
Hallinan HS	3.1	1.1	1.1	9.4	0.042	0.045
Lakeview Area	13.8	57.6	7.6	7.8	0.043	0.045
Squaw Ridge Field	0.0	0.0	0.0			
Summer Lake HS	8.9	16.5	4.1	9.0	0.042	0.045
Wart Peak Caldera	217.0	4306.0	66.0	9.0	0.064	0.430
Belknap HS	3.3	0.9	0.9	8.4	0.033	0.030
Bigelow HS	3.3	0.9	0.9	8.4	0.027	0.018
Foley HS	3.3	0.9	0.9	8.4	0.028	0.021
McCredie HS	3.3	0.9	0.9	10.3	0.027	0.019
Wall Creek HS	3.3	0.9	0.9	10.3	0.026	0.015
Generic HC Fault System	2.1	0.6	0.8	8.0	0.053	0.390
Beulah HS	3.1	1.1	1.1	9.5	0.033	0.031
Jackies Butte Field	0.0	0.0	0.0			
Jordan Craters Field	0.0	0.0	0.0			
Little Valley HS	3.1	1.1	1.1	10.4	0.033	0.031
Luce HS	3.1	1.1	1.1	8.2	0.034	0.033
McDermitt Area	3.1	1.1	1.1	8.3	0.024	0.013
Mitchell Butte HS	3.1	1.1	1.1	11.4	0.025	0.015
Heal HS	3.1	1.1	1.1	10.4	0.054	0.380
Vale HS	34.9	282.2	16.8	10.4	0.045	0.360
Breitenbush HS	3.3	0.9	0.9	9.5	0.031	0.028
Medical HS	3.3	0.9	0.9	7.0	0.026	0.017
Kahneeta HS	3.3	0.9	0.9	10.9	0.041	0.043



HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - OREGON

	RESERVOIR THERMAL ENERGY	VARIANCE	STANDARD DEVIATION	WELLHEAD THERMAL ENERGY	WELLHEAD AVAIL WORK	ELECT ENERGY
Devils Garden Area	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.00E+00	0
Fischer HS	1.09E+18	1.45E+35	3.8E+17	2.73E+17	4.5E+16	2
Four Craters Lava Field	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.0E+00	0
Glass Buttes	1.34E+19	6.99E+37	8.4E+18	3.36E+18	8.6E+17	391
Hallinan HS	1.10E+18	1.57E+35	4.0E+17	2.76E+17	4.6E+16	2
Lakeview Area	5.08E+18	7.88E+36	2.8E+18	1.27E+18	2.2E+17	10
Squaw Ridge Field	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.0E+00	0
Summer Lake HS	3.19E+18	2.33E+36	1.5E+18	7.97E+17	1.3E+17	6
Wart Peak Caldera	4.00E+18			1.00E+18	2.6E+17	116
Belknap HS	9.38E+17	8.49E+34	2.9E+17	2.35E+17	3.1E+16	1
Bigelow HS	7.97E+17	5.41E+34	2.3E+17	1.99E+17	2.2E+16	0
Foley HS	8.21E+17	5.62E+34	2.4E+17	2.05E+17	2.3E+16	1
McCredie HS	7.89E+17	5.78E+34	2.4E+17	1.97E+17	2.1E+16	0
Wall Creek HS	7.47E+17	5.35E+34	2.3E+17	1.87E+17	1.9E+16	0
Generic HC Fault System	1.02E+18	1.35E+35	3.7E+17	2.55E+17	5.4E+16	22
Beulah HS	8.76E+17	1.18E+35	3.4E+17	2.19E+17	2.9E+16	1
Jackies Butte Field	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.0E+00	0
Jordan Craters Field	0.00E+00	0.00E+00	0.0E+00	0.00E+00	0.0E+00	0
Little Valley HS	8.76E+17	8.98E+34	3.0E+17	2.19E+17	2.9E+16	1
Luce HS	9.32E+17	1.06E+35	3.3E+17	2.33E+17	3.2E+16	1
McDermitt Area	6.97E+17	5.80E+34	2.4E+17	1.74E+17	1.7E+16	0
Mitchell Butte HS	6.93E+17	6.16E+34	2.5E+17	1.73E+17	1.7E+16	0
Heal HS	1.50E+18	2.61E+35	5.1E+17	3.76E+17	8.1E+16	33
Vale HS	1.36E+19	4.29E+37	6.5E+18	3.40E+18	6.1E+17	233
Breitenbush HS	8.99E+17	6.65E+34	2.6E+17	2.25E+17	2.8E+16	1
Medical HS	8.01E+17	6.28E+34	2.5E+17	2.00E+17	2.1E+16	0
Kahneeta HS	1.14E+18	1.15E+35	3.4E+17	2.85E+17	4.7E+16	2



# GEOHERMAL ELECTRIC GENERATION SITES - OREGON

	BEST RESERVOIR THERMAL ENERGY	BEST WA/QR	BEST THERMAL UTIL FACTOR	BEST ELECTRICAL ENERGY	REMARKS
Devils Garden Area	0 (?)			0	Insufficient data.
Fischer HS	1.04E+18	0.036	0.035	1	
Four Craters Lava Field	0 (?)			0	Insufficient data.
Glass Buttes	9.55E+18	0.064	0.430	278	Estimates probably too high.
Hallinan HS	1.16E+18	0.040	0.043	2	
Lakeview Area	3.72E+18	0.043	0.045	8	
Squaw Ridge Field	0 (?)			0	Insufficient data.
Summer Lake HS	2.71E+18	0.038	0.038	4	
Wart Peak Caldera	4.00E+18	0.064	0.430	116	Intrusive nearly cooled to ambient.
Belknap HS	8.07E+17	0.031	0.028	1	
Bigelow HS	6.53E+17	0.024	0.011	0	
Foley HS	7.91E+17	0.030	0.025	1	
McCredie HS	6.94E+17	0.027	0.017	0	
Wall Creek HS	6.62E+17	0.026	0.015	0	
Generic HC Fault System	1.23E+18	0.055	0.380	27	
Beulah HS	6.93E+17	0.024	0.008	0	
Jackies Butte Field	0 (?)			0	Insufficient data.
Jordan Craters Field	0 (?)			0	Insufficient data.
Little Valley HS	9.88E+17	0.034	0.033	1	
Luce HS	9.90E+17	0.034	0.032	1	
McDermitt Area	7.50E+17	0.024	0.012	0	
Mitchell Butte HS	7.22E+17	0.024	0.015	0	
Neal HS	1.57E+18	0.052	0.390	34	
Vale HS	8.31E+18	0.045	0.330	130	
Breitenbush HS	7.49E+17	0.029	0.023	1	
Medical HS	7.29E+17	0.027	0.018	0	
Kahneeta HS	1.10E+18	0.043	0.047	2	



# HIGH TEMPERATURE GEOTHERMAL ELECTRIC GENERATION SITES - WASHINGTON

	MINIMUM RESERVOIR TEMP	MOST LIKELY RESERVOIR TEMP	MAXIMUM RESERVOIR TEMP	MEAN RESERVOIR TEMP	VARIANCE	STANDARD DEVIATION
Puny Creek Basalt Mt. Baker	?	?	?	0	0	0
Baker Hot Spring Mt. Adams (Part)	102 ?	139 ?	162 ?	0 134 0	0 153 0	0 12 0

	MINIMUM RESERVOIR AREA	MOST LIKELY RESERVOIR AREA	MAXIMUM RESERVOIR AREA	MEAN RESERVOIR AREA	VARIANCE	STANDARD DEVIATION
Puny Creek Basalt Mt. Baker				0.0	0.0	0.0
Baker Hot Springs Mt. Adams (Part)	1.0	2.0	3.0	0.0 2.0 0.0	0.0 0.2 0.0	0.0 0.4 0.0

	MINIMUM RESERVOIR THICKNESS	MOST LIKELY RESERVOIR THICKNESS	MAXIMUM RESERVOIR THICKNESS	MEAN RESERVOIR THICKNESS	VARIANCE	STANDARD DEVIATION
Puny Creek Basalt Mt. Baker				0.0	0.0	0.0
Baker Hot Springs Mt. Adams (Part)	1.0	1.5	2.5	0.0 1.7 0.0	0.0 0.1 0.0	0.0 0.3 0.0



HIGH TEMPERATURE GEOTHERMAL ELECTRIC RESOURCE SITES - WASHINGTON

	RESERVOIR VOLUME	VARIANCE	STANDARD DEVIATION	MEAN SURFACE TEMP	W/A/QR	THERMAL UTILIZATION FACTOR
Puny Creek Basalts	0.0	0.0	0.0			
Mt Baker	0.0	0.0	0.0			
Baker Hot Springs	3.3	0.9	0.9	5.6	0.040	0.04
Mt. Adams (Part)	0.0	0.0	0.0			

	RESERVOIR THERMAL ENERGY	VARIANCE	STANDARD DEVIATION	WELLHEAD THERMAL ENERGY	WELLHEAD AVAILABLE WORK
Puny Creek Basalts	00.0E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Mt. Baker	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Baker Hot Springs	1.16E+18	1.18E+35	3.4E+17	2.90E+17	4.6E+16
Mt. Adams (Part)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00

	ELECTRICAL ENERGY	BEST RESERVOIR THERMAL ENERGY	BEST ELECTRICAL ENERGY	REMARKS
Puny Creek Basalts	0	0.00E+00	0 (?)	Probably not a resource.
Mt Baker	0	0.00E+00	0	
Baker Hot Springs	2	1.08E+18	2	
Mt Adams (Part)	0	0.00E+00	0 (?)	Insufficient data.







## APPENDIX 2

### Resource Assessment Summary - Direct Use

- o Key to Units
- o Direct Use Geothermal Resource Sites - Idaho
- o Direct Use Geothermal Resource Sites - Montana
- o Direct Use Geothermal Resource Sites - Oregon
- o Direct Use Geothermal Resource Sites - Washington



## KEY TO UNITS

Temperature =  $^{\circ}\text{C}$

Area =  $\text{km}^2$

Thickness =  $\text{km}$

Volume =  $\text{km}^3$



DIRECT USE GEOTHERMAL RESOURCE SITES - IDAHO

SITE	MOST LIKELY RESERVOIR TEMPERATURE	MOST LIKELY RESERVOIR AREA	MOST LIKELY RESERVOIR THICKNESS	RESERVOIR VOLUME	BEST Mw <sup>th</sup>
Boise/Garden City	77	50.0	0.1	6.6	110
Eagle	40	6.0	0.1	0.8	5
Meridian	21			1.0	0
Western Snake River Plain	30	550.0	0.1	66.1	35
Council	22			1.0	1
Chubbuck/Pocatello	35	9.0	0.1	1.1	5
Lava Hot Springs	51			1.0	14
Hailey	83			1.0	28
Ketchum	88			1.0	30
Idaho City	63			1.0	19
Idaho Falls/Ammon	20			1.0	1
Butte City	52			1.0	15
Fairfield	31			1.0	6
Nampa/Caldwell	49	140.0	0.2	25.7	65
Parma	20			1.0	0
Soda Springs	31			1.0	5
Challis	49			1.0	13
Stanley	43			1.0	12
Glenns Ferry	63	40.0	0.1	4.3	46
Mtn. Home	21			1.0	0
Mtn. Home AFB	20			1.0	0
Preston	125			1.0	44
Ashton	91			1.0	31
Emmett	20			1.0	0
Rexburg	30			1.0	6
Paul	22			1.0	1
Malad City	29			1.0	4
Grand View	40	750.0	0.1	87.5	123
Homedale	21			1.0	0
Payette	20			1.0	0
American Falls	31	8.0	0.1	0.9	4
Buhl	45	50.0	0.1	6.8	48



# DIRECT USE GEOTHERMAL RESOURCE SITES - IDAHO

SITE	MOST LIKELY RESERVOIR TEMPERATURE	MOST LIKELY RESERVOIR AREA	MOST LIKELY RESERVOIR THICKNESS	RESERVOIR VOLUME	BEST MWth
Filer	31			1.0	5
Hansen/Kimberly	20			1.0	0
Twin Falls	38			1.0	7
Cascade	70	12.0	0.1	1.4	25



DIRECT USE GEOTHERMAL RESOURCE SITES - MONTANA

SITE	MOST LIKELY RESERVOIR TEMPERATURE	MOST LIKELY RESERVOIR AREA	MOST LIKELY RESERVOIR THICKNESS	RESERVOIR VOLUME	BEST MWth
Polaris	56			1.0	18
Townsend	24			1.0	3
Anaconda	36			1.0	9
Warm Springs	80			1.0	27
Bozeman	75			1.0	24
Clancy	82			1.0	27
Whitewall	86			1.0	29
Hot Springs	59			1.0	17
White Sulphur Springs	73			1.0	24
Lolo	60			1.0	18
Emmigrant	54			1.0	16
Gardiner	71			1.0	23
Liningston	30			1.0	6
Avon	26			1.0	4
Deer Lodge (prison)	34			1.0	8
Garrison	27			1.0	5
Grantsdale	82			1.0	27
Sula	49			1.0	14
Camas	85			1.0	28
Paradise	66			1.0	20



DIRECT USE GEOTHERMAL RESOURCE SITES - OREGON

SITE	MOST LIKELY RESERVOIR TEMPERATURE	MOST LIKELY RESERVOIR AREA	MOST LIKELY RESERVOIR THICKNESS	RESERVOIR VOLUME	BEST MWth
Baker	52			1.0	16
Haines	65			1.0	21
Huntington Area	24			1.0	3
North Powder	43			1.0	11
Government Camp	38	28.3	0.9	31.2	25
Arlington	22			1.0	1
Ritter Hot Springs	68			1.0	21
Burns Area	60	12.0	0.1	1.6	41
Parkdale	97			1.0	32
Ashland	52	3.6	0.1	0.4	25
Klamath Falls Area	60	30.0	0.1	3.7	48
Lakeview Area	62	16.0	0.1	3.0	68
Paisley Area	43	13.0	0.1	1.6	40
Oakridge Area	29			1.0	4
Adrian Area	57			1.0	15
Jordan Valley	50			1,0	13
Ontario Area	25			1.0	2
Vale HS Area	29	4.0	0.1	0.5	1
Boardman Area	26			1.0	2
Heppner Area	21			1.0	0
Irrigon Area	20			1.0	0
Lexington Area	20			1.0	0
Troutdale	50			1.0	12
Athena	21			1.0	0
Echo	22			1.0	1



DIRECT USE GEOTHERMAL RESOURCE SITES - OREGON

SITE	MOST LIKELY RESERVOIR TEMPERATURE	MOST LIKELY RESERVOIR AREA	MOST LIKELY RESERVOIR THICKNESS	RESERVOIR VOLUME	BEST MWh
Hermiston	21			1.0	0
Milton-Freewater	20			1.0	0
Pendelton	20			1.0	0
Pilot Rock	20			1.0	0
Stanfield	22			1.0	1
Umatilla	22			1.0	1
Weston	21			1.0	0
Cove Area	45	5.0	0.1	0.6	5
Imbler Area	68	88.0	0.1	9.9	102
La Grande Area	90	12.0	0.1	1.6	32
Union Area	80	6.0	0.1	0.9	14
Kahneeta Hot Springs	52			1.0	13
Rajneeshpurem	20			1.0	0
The Dalles	20			1.0	0
Spray City Well	33			1.0	6



DIRECT USE GEOTHERMAL RESOURCE SITES - WASHINGTON

SITE	MOST LIKELY RESERVOIR TEMPERATURE	MOST LIKELY RESERVOIR AREA	MOST LIKELY RESERVOIR THICKNESS	RESERVOIR VOLUME	BEST MW <sup>th</sup>
Connell-Cunningham	41	700.0	0.2	105.0	73
Lino	21			1.0	1
Othello	54	300.0	0.2	75.6	87
Ritzville	20			1.0	0
Washtucna	25			1.0	2
Clarkston	23			1.0	1
Benton City	22			1.0	1
Kennewick	23			1.0	1
Prosser	25			1.0	2
Richland	21			1.0	0
West Richland	21			1.0	0
Wenatchee/East Wenatchee	20			1.0	0
Pasco	21			1.0	0
Pomeroy	23			1.0	1
Ephrata	30	300.0	0.2	75.6	26
Moses Lake	35	1000.0	0.1	116.7	60
Soap Lake	27		0.1	1.0	3
Warden	23			1.0	1
Ellensburg	21			1.0	1
Wahkiacus	29			1.0	4
Davenport	24			1.0	3
Odessa	35	300.0	0.1	33.1	40
Reardon					
N. Bonneville	36			1.0	7
Stevenson	34			1.0	6
St. Martin's HS Resort	42			1.0	9
Cheney	29			1.0	4
Walla Walla/College Place	41	350.0	0.1	36.9	57
Colfax	24			1.0	2
Pullman	21			1.0	2
Grandview	23			1.0	1



DIRECT USE GEOTHERMAL RESOURCE SITES - WASHINGTON

SITE	MOST LIKELY RESERVOIR TEMPERATURE	MOST LIKELY RESERVOIR AREA	MOST LIKELY RESERVOIR THICKNESS	RESERVOIR VOLUME	BEST MWth
Granger	20			1.0	0
Harrah	26			1.0	2
Mabton	23			1.0	1
Sunnyside	20			1.0	0
Toppenish	21			1.0	0
Yakima	36	1000.0	0.1	108.9	62
Zillah	27			1.0	3







## APPENDIX 3

### Electrical Generation (High Temperature) Resource Assessment

- o Program Documentation
- o Program Listing



## HIGH TEMPERATURE RESOURCE PRINTOUTS

The high temperature printouts for geothermal resources in the four state area were completed on LOTUS 123 database management spreadsheets. Following is a brief explanation of those spreadsheets. The "Column Label" is the column heading as it appears on the spreadsheet. The "Column Address" is the letter designation of the column. It does not appear on the printout. The "Text Symbol" is the symbol which stands for the variable in the explanatory text of Chapter 3. The "Column Formula" is the actual equation in the spreadsheet which is used to calculate the variable.



HIGH TEMPERATURE RESOURCE PRINTOUT EXPLANATION

COLUMN LABEL	COLUMN ADDRESS	TEXT SYMBOL	COLUMN FORMULA
Minimum Reservoir Temperature	D	T <sub>1</sub>	---
Most-Likely Reservoir Temperature	E	T <sub>2</sub>	---
Maximum Reservoir Temperature	F	T <sub>3</sub>	---
Mean Reservoir Temperature	G	T <sub>avr</sub>	(D+E+F)/3
Variance	H	Var [T]	$((E-D)^2+(F-E)^2+(E-D)*(F-E))/18$
Standard Deviation	I	S.d.	$\sqrt{H}$
Minimum Reservoir Area	K	A <sub>1</sub>	---
Most-Likely Reservoir Area	L	A <sub>2</sub>	---
Maximum Reservoir Area	M	A <sub>3</sub>	---
Mean Reservoir Area	N	A <sub>avr</sub>	(K+L+M)/3
Variance	O	Var [A]	$((L-K)^2+(M-L)^2+(L-K)*(M-L))/18$
Standard Deviation	P	S.d.	$\sqrt{O}$
Minimum Reservoir Thickness	R	Th <sub>1</sub>	---
Most-Likely Reservoir Thickness	S	Th <sub>2</sub>	---
Maximum Reservoir Thickness	T	Th <sub>3</sub>	---
Mean Reservoir Thickness	U	Th <sub>avr</sub>	(R+S+T)/3
Variance	V	Var [Th]	$((S-R)^2+(T-S)^2+(S-R)*(T-S))/18$
Standard Deviation	W	S.d.	$\sqrt{V}$
Reservoir Volume	Y	V	N*U
Variance	Z	Var [V]	$(O+N)^2*(V+U)^2-N^2*U^2$
Standard Deviation	AA	S.d.	$\sqrt{Z}$
Mean Surface Temperature	AC	T <sub>0</sub>	---



COLUMN LABEL	COLUMN ADDRESS	TEXT SYMBOL	COLUMN FORMULA
Wa/Q <sub>r</sub>	AD	Wa/Q <sub>r</sub>	---
Thermal Utilization Factor	AE	N	---
Reservoir Thermal Energy	AG	Q <sub>r</sub>	$(2.7 \times 10^{15}) * Y * (G-AC)$
Variance	AH	Var [Q]	(below)
$(2.7 \times 10^{15})^2 * (H + (G-AC)^2) * (O + N^2) * (V + U^2) - (2.7 \times 10^{15})^2 * N^2 * U^2$			
Standard Deviation	AI	S.d.	$\sqrt{AH}$
Wellhead Thermal Energy	AK	Q <sub>wh</sub>	.25* AG
Wellhead Available Work	AL	W <sub>a</sub>	AD*AG
Electrical Energy	AN	MW <sub>e</sub>	AL*AE/9.47x10 <sup>14</sup>
Best Reservoir Thermal Energy	AP	Q <sub>r</sub> (best)	$(2.7 \times 10^{15}) * (L) * (S) * (E-AC)$
Best Electrical Energy	AR	MW <sub>e</sub> (best)	AD*AP*AE/ 9.47x10 <sup>14</sup>
Remarks	AT	---	---







## APPENDIX 4

### Direct Utilization (Low Temperature) Resource Assessment

- o Program Documentation
- o Program Listing



## LOW TEMPERATURE RESOURCE PRINTOUTS

The low temperature printouts for geothermal resources in the four state area were completed on LOTUS 123 database management spreadsheets. Following is a brief explanation of those spreadsheets. The "Column Label" is the column heading as it appears on the spreadsheet. The "Column Address" is the letter designation of the column. It does not appear on the printout. The "Text Symbol" is the symbol which stands for the variable in the explanatory text of Chapter 3. The "Column Formula" is the actual equation in the spreadsheet which is used to calculate the variable.



LOW TEMPERATURE RESOURCE PRINTOUT EXPLANATION

COLUMN LABEL	COLUMN ADDRESS	TEXT SYMBOL	COLUMN FORMULA
Minimum Reservoir Temperature	D	T <sub>1</sub>	---
Most-Likely Reservoir Temperature	E	T <sub>2</sub>	---
Maximum Reservoir Temperature	F	T <sub>3</sub>	---
Mean Reservoir Temperature	G	T <sub>avr</sub>	$(D+E+F)/3$
Variance	H	Var[T]	$((E-D)^2+(F-E)^2+(E-D)*(F-E))/18$
Standard Deviation	I	S.D.	$\sqrt{H}$
Minimum Reservoir Area	K	A <sub>1</sub>	---
Most-Likely Reservoir Area	L	A <sub>2</sub>	---
Maximum Reservoir Area	M	A <sub>3</sub>	---
Mean Reservoir Area	N	A <sub>avr</sub>	$(K+L+M)/3$
Variance	O	Var[A]	$((L-K)^2+(M-L)^2+(L-K)*(M-L))/18$
Standard Deviation	P	S.D.	$\sqrt{O}$
Minimum Reservoir Thickness	R	Th <sub>1</sub>	---
Most-Likely Reservoir Thickness	S	Th <sub>2</sub>	---
Maximum Reservoir Thickness	T	Th <sub>3</sub>	---
Mean Reservoir Thickness	U	Th <sub>avr</sub>	$(R+S+T)/3$
Variance	V	Var[Th]	$((S-R)^2+(T-S)^2+(S-R)*(T-S))/18$
Standard Deviation	W	S.D.	$\sqrt{V}$
Volume	Y	V	
Variance	Z	Var[V]	$If(y=1,.165,(O+N)^2*(V+U)^2-N^2*U^2)$
Standard Deviation	AA	S.D.	$\sqrt{Z}$
Mean Surface Temperature	AC	T <sub>0</sub>	---



COLUMN LABEL	COLUMN ADDRESS	TEXT SYMBOL	COLUMN FORMULA
Average $A_w$	AD	$A_w$	---
Most-Likely $A_w$	AE	$A_w$	---
Accessible Resource Base	AG	$Q_r$	$(2.6 \times 10^{15}) * Y * (G-AC)$
Variance	AH	$Var[Q]$	(below)
If $(y=1, (2.6 \times 10^{15})^2 * (Z+Y^2) * (H+(G-AC)^2) - y^2 * (G-AC)^2 * (2.6 \times 10^{15})^2, (2.6 \times 10^{15})^2 * (H+(G-AC)^2) * (O+N^2) * (V+U^2) * (V+U^2) - (2.6 \times 10^{15})^2 * (G-AK)^2 * N^2 * U^2)$			
Standard Deviation	AI	S.D.	$\sqrt{AH}$
Resource	AK	$Q_{wh}$	(below)
If $(y=1, .25*AG, 1.214 \times 10^{14} * .5*N*(G-AC)/AD)$			
$Q_{wh}/Q_r$	AL	$Q_{wh}/Q_r$	AK/AG
Beneficial Heat	AM	$Q_{ben}$	$AK*.6*(G-(AC+10))/(G-AC)$
Megawatts Thermal	AN	$MW_t$	$AM/9.47 \times 10^{14}$
Best $Q_r$	AP	$Q_r$ (best)	(below)
If $(y=1, 2.6 \times 10^{15} * Y * (E-AC), 2.6 \times 10^{15} * L * S * (E-AC))$			
Best $Q_{wh}$	AQ	$Q_{wh}$ (best)	(below)
If $(y=1, .25*AP, 1.214 \times 10^{14} * .5*L * (E-AC)/AE)$			
Best $Q_{ben}$	AR	$Q_{ben}$ (best)	$AQ*.6*(E-(AC+10))/(E-AC)$
Best $MW_{th}$	AS	$MW_t$ (best)	$AR/9.47 \times 10^{14}$
Remarks	AU	---	---







## APPENDIX 5

### CENTPLANT Program

- o Summary
- o Program Operation and Listing
- o Cost Relationships for Geothermal Power Plants and Wellfield Surface Facilities (Bechtel 1985)



## SUMMARY

### Electrical Generation Computer Program "CENTPLANT" and Related Documentation

The methodology of this report has used published estimates from a number of existing plants and cost estimates from Bechtel National, Inc. conceptual, preliminary, and detailed designs. This wealth of data allowed development of generic wellfield and plant cost relationships for resources 177°C (350°F) and higher.

The Bechtel report discusses background and data sources for cost relationships in its first section. Next, facilities and performance of geothermal power plants are presented, followed by capital cost relationships for plants having 10 to 100 MW capacity. The third section develops O&M estimates for the power plants. Fourth, wellfield surface facilities are described and capital cost relationships are then presented. The sixth section addresses adjustments for the cost relationships. The seventh and final section presents a detailed procedure for applying the results of the previous steps.

This methodology was modified by ODOE and developed into a spreadsheet program called CENTPLANT. Results of the analysis, CENTPLANT cost estimates are shown in the following CENTPLANT cost estimate table.

The listing of the CENTPLANT program is shown here as it appears on a Lotus 123 (TM) spreadsheet formula printout. The Bechtel portion of the documentation includes the original formulas developed for ODOE. Only costs and certain output changes have been added. No substantive changes of the engineering formulas have been made.



# CENTPLANT Cost Estimates

<u>Site</u>	<u>Resource Temp.(°C)<sup>1</sup></u>	<u>Conversion Process<sup>2</sup></u>	<u>Estimated Capital Cost (\$/Net KW)<sup>3</sup></u>	<u>Estimated O &amp; M Cost (\$/KW/YR)<sup>4</sup></u>
Newberry Volcano	258	SF	2899	49
Wart Peak Caldera	233	SF	3055	62
Glass Buttes	233	SF	3075	63
Cappy-Burn Butte	233	SF	3232	62
Mickey HS	216	SF	3240	65
Bearwallow Butte	233	SF	3369	61
Melvin/3-Creek Buttes	233	SF	3379	61
Vale HS	155	B	3524	81
Klamath Falls area	172	DF	3541	87
Olene Gap HS	175	DF	3544	87
Klamath Hills area	177	DF	3565	87
Neal HS	188	DF	3580	85
Crump HS	178	DF	3588	88
Borax Lake HS	191	DF	3688	90
Alvord HS	181	DF	3754	90
Trout Creek area	154	DF	3774	92
Crater Lake area	185	DF	3951	89
Generic High Cascades	185	DF	4014	89
Mt. McLoughlin	185	DF	4066	90
Subtotal:	19 (all Oregon)			

<sup>1</sup> Either measured or most likely geothermometer estimate.

<sup>2</sup> SF = single flash, DF = double flash, B = binary.

<sup>3</sup> Costs are complete for a 50 MW net field and plant. Power plant costs alone are approximately one third those shown. See Appendix 6 for details.

<sup>4</sup> Costs include operating labor, maintenance, and overhead.

## I. What is CENTPLANT?

The CENTPLANT computer program is used to estimate the capital costs for a given geothermal resource. The estimates are based upon the temperature, the flow rate, and the location of the source.

CENTPLANT was originally developed by ODOE from information provided by Bechtel National. Later, it was written for a Wang Computer in Multiplan. This version is a translation of the Multiplan program. This version is designed to run as a LOTUS spreadsheet program using a COMPAQ computer with MS.DOS 2.0 operating system.

## II. Starting the Program

The program is located on the disk at the back of this manual. It is titled CENPLAN (The spelling difference here is due to the limit of 8 characters in a file name. I shall refer to the program as CENTPLANT throughout this document, however, and the reader must understand that the disk's filename is spelled slightly different.) But remember that you must be LOTUS to use this program. So follow these steps to start the program.

1. Put the CENTPLANT disk in drive B of your computer. (Or copy the program to the harddisk if you are using a computer with a harddisk. You will also need to change the default drive setting in LOTUS to recognize the harddisk. The rest of this explanation assumes that you are using a dual floppy disk system).

2. Insert the LOTUS program disk in Drive A and start a new Lotus 123 spreadsheet application.

3. Using the File Retrieve command in LOTUS, select the CENTPLANT program. When the CENTPLANT program is retrieved, you will be ready to use it for calculations.

(Note: a backup copy of the CENTPLANT disk is kept in the data processing office. Should this CENTPLANT disk become damaged or lost, you can make a copy of the backup disk and continue with your calculations. However, you should never use the backup disk, it should only be copied. )

## II. Using the program.

The CENTPLANT spreadsheet is relatively simple. There is an input section and an output section. The input section is located in the upper left hand corner of the spreadsheet. (see the spreadsheet map on the following page) Directly below the input section is the output section. Both the input and the output sections have several parameters.

The equation references in the output section refer to the equations in the Bochtel manual titled: 'GDS' RELATIONSHIPS FOR GEOTHERMAL POWER PLANTS: WELLFIELD SURFACE FACILITIES', 1985. This manual also provides information about the input variables and overall assumptions of the program.

Altering the variables in the input section will automatically alter the output values. (Make sure the calculation setting for the LOTUS program is set to automatic if changes in the output are not occurring.) The input section is the only place you should try to modify values.

# CENTPLANT

## SPREADSHEET MAP

A1

TITLES	
INPUT	F4
	F24
OUTPUT	F53

## CODE LIST

A1: 'BECHTEL/ODOE COST ESTIMATE SHEET  
A2: 'CENPLAN 21Feb85 Ver 1 JDM WSOE  
B2: ' SITE  
C2: 'Newberry Volcano  
A4: '\*\*\*\*\*INFUT\*\*\*\*\*  
A5: 'Resource Temperature  
B5: 258  
C5: 'deg C  
D5: "a1=  
E5: (F3) 2.4  
A6: 'Net Capacity  
B6: 10  
C6: 'MW  
D6: "b1=  
E6: (F3) 0.699  
A7: 'Technology (SF, DF, B)  
B7: "SF  
D7: "c1=  
E7: (F3) 0.03  
A8: 'Terrain Labor Factor (Y=1,N=0)  
B8: 0  
D8: "a2=  
E8: (F3) 0.178  
A9: 'Terrain Site Prep (Y=1,N=0)  
B9: 1  
D9: "b2=  
E9: (F3) 1  
A10: 'Construction Camp (Y=1,N=0)  
B10: 0  
D10: "a3=  
E10: (F3) 0.47  
A11: 'Plant O & M: Low, Prob., or High  
B11: "P  
D11: "b3=  
E11: (F3) 0.7  
A12: 'Production Equip.: L, F, H  
B12: "P  
D12: "c2=  
E12: (F3) 0.06  
A13: 'Injection Equip.: L, F, H  
B13: "P  
A14: 'Well O & M: L, F, H  
B14: "P  
A15: 'Electricity cost  
B15: 3.15  
C15: 'cents/kWh  
A16: 'Interest rate  
B16: 13.5  
C16: '%  
A17: 'Distance to Trans. Lines  
B17: 12  
C17: 'km  
D17: "K=  
E17: 0.000992

## CODE LIST (Continued)

A18: 'Remaining Assessment Work  
B18: 2.985  
D18: '(input)  
A19: 'Permits/Licenses  
B19: 0.05  
D19: '(input)  
A20: 'Production & Injection Wells  
B20: 11  
D20: '(input)  
A21: 'Dry Well(s)  
B21: 2  
A24: '\*\*\*\*\*OUTPUT\*\*\*\*\*  
B24: '(in \$ million)  
D24: 'REFERENCES  
A26: 'Wellfield Capital Costs  
D26: 'Eq. 7.2  
A27: 'Production Equipment  
B27:  $+E8*(B6^{E9})$   
D27: 'Eq. 7.3.1  
A28: 'Injection Equipment  
B28:  $+E10*(B6^{E11})$   
D28: 'Eq. 7.3.2  
A29: 'Terrain Labor Adj.  
B29:  $@IF(B8=1,((B27+B28)*0.02),0)$   
D29: 'Eq. 7.3.3  
A30: 'Terrain Site Prep. Adj.  
B30:  $@IF(B9=1,((B27+B28)*0.02),0)$   
D30: 'Eq. 7.3.3  
A31: 'Construction Camp  
B31:  $@IF(B10=1,(0.109*(B6^{0.5}))+ (0.037*(B6^{0.78})),0)$   
D31: 'Eq. 7.3.3  
A32: 'S u b t o t a l (wellfield)  
B32:  $@SUM(B27..B31)$   
D32: 'sum  
A33: 'Wellfield O & M Costs  
B33:  $(((((1.85*E12)*B32)+B15)*0.84)*E17)*B6)$   
D33: 'Eq. 7.4  
A35: 'Power Plant Capital Costs  
A36: 'Power Plant  
B36:  $+E5*(B6^{E6})$   
D36: 'Eq. 7.1.1  
A37: 'H2S Abatement  
B37:  $0.838*(B6^{0.426})$   
D37: 'Eq. 7.1.2  
A38: 'Terrain Labor Adj.  
B38:  $@IF(B8=1,((B36+B37)*0.02),0)$   
D38: 'Eq. 7.1.3  
A39: 'Terrain Site Prep. Adj.  
B39:  $@IF(B9=1,((B36+B37)*0.02),0)$   
D39: 'Eq. 7.1.3  
A40: 'Construction Camp  
B40:  $@IF(B10=1,((0.266*(B6^{0.5}))+ (0.11*(B6^{0.78}))),0)$   
D40: 'Eq. 7.1.3  
A41: 'S u b t o t a l (pwr plant)

CODE LIST (Continued)

B41: @SUM(B36..B40)  
D41: 'sum  
A42: 'Plant O & M Costs  
B42: 1.77\*E7\*B41  
A45: 'Transmission Line Costs  
B45: +B17\*0.119375  
D45: '(BPA 115KV #s)  
A47: 'Contingency @ 20%  
B47: @SUM(B18..B21,B32,B41,B45)\*0.2  
A49: 'Total Capital Costs  
B49: @SUM(B18..B21,B32,B41,B45,B47)  
A50: ' (\$ per Net KW)  
B50: +B49\*1000/B6  
A52: 'Total O & M Costs  
B52: +B33+B42  
A53: ' (\$ per Net KW)  
B53: +B52\*1000/B6

THIS IS A SAMPLE OF THE SPREADSHEET:

BECHTEL/DDOE COST ESTIMATE SHEET

CENPLAN 21Feb85 Ver 1 JDM WSOE SITE

Newberry Volcano

\*\*\*\*\*INPUT\*\*\*\*\*

Resource Temperature	258 deg C	a1=	2.400
Net Capacity	10 MW	b1=	0.695
Technology (SF, DF, B)	SF	c1=	0.030
Terrain Labor Factor (Y=1,N=0)	0	a2=	0.178
Terrain Site Prep (Y=1,N=0)	1	b2=	1.000
Construction Camp (Y=1,N=0)	0	a3=	0.470
Plant O & M: Low, Prob., or High	P	b3=	0.700
Production Equip.: L, P, H	P	c2=	0.060
Injection Equip.: L, P, H	P		
Well O & M: L, P, H	P		
Electricity cost	3.15 cents/kWh		
Interest rate	13.5 %		
Distance to Trans. Lines	12 km	K=	0.000992
Remaining Assessment Work	2.985	(input)	
Permits/Licenses	0.05	(input)	
Production & Injection Wells	11	(input)	
Dry Well(s)	2		

\*\*\*\*\*OUTPUT\*\*\*\*\* (in \$ million)

REFERENCES

Wellfield Capital Costs		Eq. 7.2
Production Equipment	1.78	Eq. 7.3.1
Injection Equipment	2.355579	Eq. 7.3.2
Terrain Labor Adj.	0	Eq. 7.3.3
Terrain Site Prep. Adj.	0.082711	Eq. 7.3.3
Construction Camp	0	Eq. 7.3.3
S u b t o t a l (wellfield)	4.218291	sum
Wellfield O & M Costs	0.030149	Eq. 7.4
Power Plant Capital Costs		
Power Plant	12.00082	Eq. 7.1.1
H2S Abatement	2.234827	Eq. 7.1.2
Terrain Labor Adj.	0	Eq. 7.1.3
Terrain Site Prep. Adj.	0.284713	Eq. 7.1.3
Construction Camp	0	Eq. 7.1.3
S u b t o t a l (pwr plant)	14.52036	sum
Plant O & M Costs	0.771031	
Transmission Line Costs	1.4325	(BPA 115KV #s)
Contingency @ 20%	7.241232	
Total Capital Costs	43.44739	
(\$ per Net KW)	4344.739	
Total O & M Costs	0.801181	
(\$ per Net KW)	80.11816	

# **COST RELATIONSHIPS FOR GEOTHERMAL POWER PLANTS AND WELLFIELD SURFACE FACILITIES**

Prepared for

**DEPARTMENT OF ENERGY  
STATE OF OREGON**

Contract No. C50080  
Bechtel Job No. 17133

by

**Bechtel National, Inc.  
San Francisco, California**



February 1985

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## ABSTRACT

The objective of this study is to develop generic capital and O&M cost relationships for geothermal power plants and wellfield surface facilities for the range of plant capacity from 10 to 100 MWe net. These relationships are to be used by the Oregon Department of Energy, the Washington State Energy Office, and others to perform economic screening of geothermal resource sites in the Bonneville Power Administration (BPA) region for a BPA-funded study.

Capital and O&M cost relationships for September 1984 price levels are developed and presented in graphs and equations for the following resource conditions and types of power plants and their associated wellfield surface facilities:

- o Steam resource, direct steam plant
- o 530°F hot water resource, single flash plant
- o 530°F hot water resource, double flash plant
- o 420°F hot water resource, single flash plant
- o 420°F hot water resource, double flash plant
- o 350°F hot water resource, double flash plant
- o 350°F hot water resource, binary plant

In addition, the Biphase and Ormat units are described, and cost estimates and performance data are presented for the hot water resource temperatures indicated below:

- o Biphase - 350, 420, and 530°F
- o Ormat - 250, 300, and 350°F



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## Section 1

### INTRODUCTION AND BACKGROUND

#### 1.1 INTRODUCTION

This report presents generic capital and operating and maintenance (O&M) cost relationships for geothermal power plants and wellfield surface facilities. These cost relationships were prepared for the Oregon Department of Energy by Bechtel National, Inc. as part of a study to identify the geothermal energy potential within the Bonneville Power Administration (BPA) region. The following paragraph describes the overall study and the use that will be made of the cost relationships developed by Bechtel.

The BPA has entered into an agreement with the Washington State Energy Office (WSEO) to conduct activities related to the identification of the geothermal energy potential within the BPA region. The WSEO in turn has agreements with the following additional state agencies within the BPA region to participate in preparing the work products required under the agreement with the BPA:

- o Idaho Department of Water Resources
- o Montana Department of Natural Resources and Conservation
- o Oregon Department of Energy
- o Oregon Department of Geology and Mineral Industries

The objective of the overall study is to consolidate and evaluate existing geothermal resource data for the Pacific Northwest region. To do this, the work is divided into the following activities:

- o Characterize electric generation resources (resource temperature equal to or greater than 90°C). This includes estimating the energy cost for each site.

- o Characterize direct use resources (resource temperature less than 90°C).
- o Review legal, institutional, and environmental requirements that affect resource development.
- o Rank geothermal resource sites.

The objective of the Bechtel work with the Oregon Department of Energy is to develop generic capital and O&M cost relationships for geothermal power plants and wellfield surface facilities for the range of plant capacity from 10 to 100 MWe net. This work by Bechtel will furnish industry input into the cost information used for screening the various geothermal resource prospects. In this way, realistic estimates for generic costs of facilities can be used in the economic screening phase of the overall BPA study.

Section 1.2, following, discusses the background and data sources for developing the desired generic cost relationships.

Section 2 of this report briefly describes the facilities and performance of geothermal power plants, and presents capital cost relationships for plants having 10 to 100 MWe capacity. Section 3 develops O&M cost estimates for the power plants.

Section 4 describes the wellfield surface facilities needed to support geothermal power plants and presents capital cost relationships for them. Section 5 develops estimates of O&M costs for wellfield surface facilities.

Section 6 addresses some adjustments to the cost relationships presented in Sections 2 through 5 that may be appropriate for certain special conditions. It also presents a method for calculating interest during construction.

Section 7 presents a step-by-step procedure for applying the results of this report in the calculation of capital and O&M cost estimates needed

for the economic screening that is to be done by others as part of the overall BPA study.

## 1.2 BACKGROUND

The data used for developing the desired generic cost relationships include published estimates for a number of plants that have been constructed and cost estimates from Bechtel conceptual, preliminary, and detail designs. These data sources are summarized in Table 1-1.

For direct steam power plants, a reasonably large amount of data are available due to the extensive development at The Geysers that currently includes 20 generating units ranging from 11 to 135 MWe (net). However, the cost data available for plants using hot water resources is not nearly as extensive, since construction in the United States has only recently begun on plants that use these resources. Currently, there are four operating power plants of 10 MWe or more capacity in the United States using hot water resources - the 11 MWe (gross) binary plant at East Mesa (California), the 10 MWe (gross) flashed steam plants at Brawley (California) and Salton Sea (California), and the 20 MWe (net) flashed steam plant at Roosevelt Hot Springs (Utah). Four other plants ranging in size from 7 to 47 MWe (net) are under construction but are not yet operating - the 47 MWe (net) flashed steam plant at Heber (California), the 45 MWe (net) binary plant at Heber, the 7 MWe (net) binary plant at Mammoth (California), and the 9 MWe (net) flashed steam plant at Desert Peak (Nevada). These eight plants use hot water resources ranging from 350°F to over 500°F. About 118 geothermal power generating units are operating elsewhere in the world, but cost data for them was not used in this study because of the great difficulty in obtaining, interpreting, and analyzing cost data from other countries.

Plants of the same capacity but using hot water resources with different temperatures and different energy conversion processes would be expected to have somewhat different costs. Therefore, cost relationships were developed for the resource conditions and energy conversion processes indicated in Table 1-2. This classification makes maximum use of

Table 1-1

## SOURCES OF COST ESTIMATE DATA

Plant No.	Plant Identification	Plant Capacity (MWe net)	Scope	Plant Type	Resource Temp. (°F)	Source of Data	Year of Est.
1	Private client	24	P	DS	NA	Conceptual design	1983
2	SMUDGE 1	72	P	DS	NA	Published in licensing documents	1979
3	Private client	80	P	DS	NA	Conceptual design	1980
4	Unit 17, PG&E	110	P	DS	NA	Published in licensing documents	1978
5	Unit 18, PG&E	110	P	DS	NA	Published in licensing documents	1979
6	Private client	106	P	DS	NA	Design estimate	1980
7	Private client	5	P	DS	NA	Conceptual design	1982
8	Unit 21, PG&E	106	P	DS	NA	Published in licensing documents	1984
9	Private client	72	WF	DS	NA	(a)	1984
10	Private client	53	WF	DS	NA	(b)	1984
11	Private client	113	WF	DS	NA	(a)	1984
12	Private client	135	WF	DS	NA	(b)	1984
13	Baca, PNM	46	P	SF	530	Definitive estimate (Bechtel)	1980
14	Private client	106	P	SF	530	Conceptual design	1981
15	Milford No. 1, UP&L	20	P&WF	SF	500	Published data	1984
16	Brawley, SCE	9	P	SF	420 <sup>(c)</sup>	Published data	1980
17	Private client	9	P	SF	420	Conceptual design	1980
18	Salton Sea, SCE	9	P	SF	420 <sup>(c)</sup>	Published data	1982
19	Private client	53	P	DF	530	Conceptual design	1981
20	Private client	46	P	DF	530	Conceptual design	1977
21	Private client	42	P,WF	DF	420 <sup>(c)</sup>	Conceptual design	1983
22	Private client	21	P,WF	DF	420 <sup>(c)</sup>	Conceptual design	1983
23	Private client	11	P	DF	420 <sup>(c)</sup>	Conceptual design	1984
24	Private client	45	P	DF	420	Conceptual design	1978
25	Private client	50	P	DF	420 <sup>(c)</sup>	Conceptual design	1980
26	Heber, SCE	47	P	DF	350	Published in licensing documents	1984
27	Private client	47	WF	DF	350	Conceptual design	1981
28	Private client	45	P	DF	350	Conceptual design	1976
29	Heber Binary	45	P	Binary	350	Definitive estimate (DOE)	1984
30	Beowawe	8	P	Binary	350	Published data	1983
31	Mammoth	7	P	Binary	350	Published data	1982
32	Heber Proof-of-Concept, ERDA	10	P	Binary	350	Conceptual design (Bechtel)	1975

P - Power plant  
 WF - Wellfield  
 NA - Does not apply

SF - Single flash  
 DF - Double flash  
 DS - Direct steam

(a) Cost from a revised conceptual design estimate

(b) Cost from an adaptation of a previous conceptual design estimate

(c) Wellhead enthalpy is equal to that for pure water at the indicated temperature

Table 1-2

RESOURCE CONDITIONS AND CONVERSION PROCESSES  
FOR COST RELATIONSHIPS

<u>Resource</u>	<u>Conversion Process</u>			
	<u>Direct Steam</u>	<u>Single Flash</u>	<u>Double Flash</u>	<u>Binary</u>
Steam (Similar to The Geysers)	X			
Hot water (530°F)		X	X	
Hot water (420°F)		X	X	
Hot water (350°F)			X	X

available cost data and accounts for the cost effects of resource temperature in the range of temperatures that have been exploited to date with plants having 10 MWe capacity and greater.

Besides resource temperature and type of energy conversion process, a number of other technical characteristics may affect the cost of geothermal power plants. For example, if the hydrogen sulfide ( $H_2S$ ) content of the geothermal fluids is low, there may be no need for an  $H_2S$  abatement system; on the other hand, all the power plants at The Geysers are required to have equipment for abating  $H_2S$  to meet California air quality requirements.

To account for the major technical characteristics that may affect the cost of geothermal power facilities, these characteristics are identified, and descriptions of low, probable, and high cost installations are provided for each characteristic, as shown in Table 1-3. Generic cost relationships for plants with capacity from 10 to 100 MWe (net) are provided to account for each of these situations. The "probable cost" in each case is based on the expected requirement in the study region. In many cases, resource data are not

Table 1-3

TECHNICAL CHARACTERISTICS AFFECTING COST  
OF GEOTHERMAL POWER PROJECTS

Item	Low Cost	Probable Cost	High Cost
<b>CAPITAL COSTS</b>			
<u>Power Plant</u>			
H <sub>2</sub> S abatement (steam and flashed steam power plants)	No H <sub>2</sub> S abatement required	H <sub>2</sub> S abatement costs similar to design for The Geysers	H <sub>2</sub> S abatement costs similar to design for The Geysers
<u>Wellfield Surface Facilities</u>			
Production facilities (steam resource)	Low edge of estimates	Mean of estimates	Mean of estimates
Production facilities (hot water resource)	Single well island near power plant	Well islands with maximum of six wells per island	Single wells distributed uniformly over the wellfield
Reinjection facilities (steam resource)	Reinjection not required	Typical of The Geysers	Typical of The Geysers
Reinjection facilities (hot water resource)	Reinjection not required	Reinjection with no spent brine treatment; one reinjection island located one mile from the power plant	Reinjection with no spent brine treatment; reinjection wells uniformly distributed; center of reinjection field is one mile from power plant
<b>O&amp;M COSTS</b>			
<u>Power Plant</u>			
Corrosion severity	Low end of scale in EPRI TAG (Ref. 1-1)	Low end of scale in EPRI TAG	Mid range of scale in EPRI TAG <sup>(a)</sup>
Number of units monitored by one crew of operators	6 (steam and flashed steam units) 4 (binary units)	One	One
<u>Wellfield Surface Facilities</u>			
Corrosion severity (steam resource)	Low end of scale in EPRI TAG	Low end of scale in EPRI TAG	Mid range of scale in EPRI TAG
Corrosion severity (hot water resource)	Midpoint of scale in EPRI TAG	Midpoint of scale in EPRI TAG	High end of scale in EPRI TAG
Number of wellfields monitored by one crew of operators (units)	6 (steam and binary units) 4 (flashed steam units)	One	One
Reinjection pumping (hot water resource)	Not required	P = 250 psi	P = 500 psi
- Production pumping (binary plant for hot water resource)	P = 250 psi	P = 250 psi	P = 500 psi

(a) The extremes of the relative cost level for the study area do not necessarily coincide with the extremes of the range in the EPRI TAG.

presently adequate for assessing the requirements, so the designation of "probable cost" is somewhat speculative until adequate resource data are available.

In addition to the characteristics discussed above, the following additional factors may influence capital costs:

- o Terrain. Two distinct types of terrain that may affect construction costs exist in the study area. Relatively flat, open terrain occurs in eastern Washington and Oregon, southern Idaho, and many of the river valleys in Montana. In these areas, construction sites would be accessible by road without undue traffic congestion or hazard, and earth moving for site preparation would be minimal. On the other hand, in the mountainous regions of all four states, site access could be a considerable problem, and site preparation may require moving a large amount of soil and rock.
- o Local construction labor. Some of the remote geothermal resources may be a long distance from an adequate pool of construction labor. Construction at such a remote site would increase costs compared to building at a location within a reasonable distance of adequate construction labor.

To account for these two factors, cost relationships are first developed for relatively flat, open terrain for sites in areas with adequate local construction labor. Adjustments to these initial cost relationships to take into account mountainous terrain and areas with inadequate local construction labor are developed in Section 6.



## Section 2

### CAPITAL COSTS OF POWER PLANTS

#### 2.1 DESCRIPTION OF POWER PLANT

The fundamental thermal power plant process involves the passage of high-pressure, high-temperature vapor through a series of alternating stationary and rotating blades in a turbine. During this expansion process, thermal energy of the vapor is transferred to the rotating blades and converted to mechanical energy which operates an electrical generator. The vapor that passes through the turbine is steam for direct steam or flashed steam plants and hydrocarbon or fluorocarbon for binary plants. Almost all commercial power turbines exhaust to a water-cooled condenser operating under a vacuum rather than exhausting to the atmosphere. This allows more energy to be extracted from the vapor flow.

##### 2.1.1 Direct Steam Process

A direct steam process is illustrated in Figure 2-1. In this process, steam from geothermal wells passes through particle and moisture separators into a turbine. The turbine exhaust is condensed by either a direct contact condenser (where steam and cooling water are mixed together) or a surface condenser (where cooling water flows inside tubes and steam condenses outside them). Unit size for recent commercial installations has been about 50 MWe, with the largest being 135 MWe. Since geothermal steam often contains hydrogen sulfide ( $H_2S$ ), abatement systems are frequently needed to prevent the release of this noxious gas into the atmosphere.

##### 2.1.2 Flashed Steam Process

Nearly all current commercial power plants utilizing hot water resources use a flashed steam process, as illustrated in Figures 2-2 and 2-3. Steam is generated by flashing hot water in the wellbore, in a flash tank, or in both, depending on resource conditions. The power plant customarily interfaces with the wellfield at two points: the steam

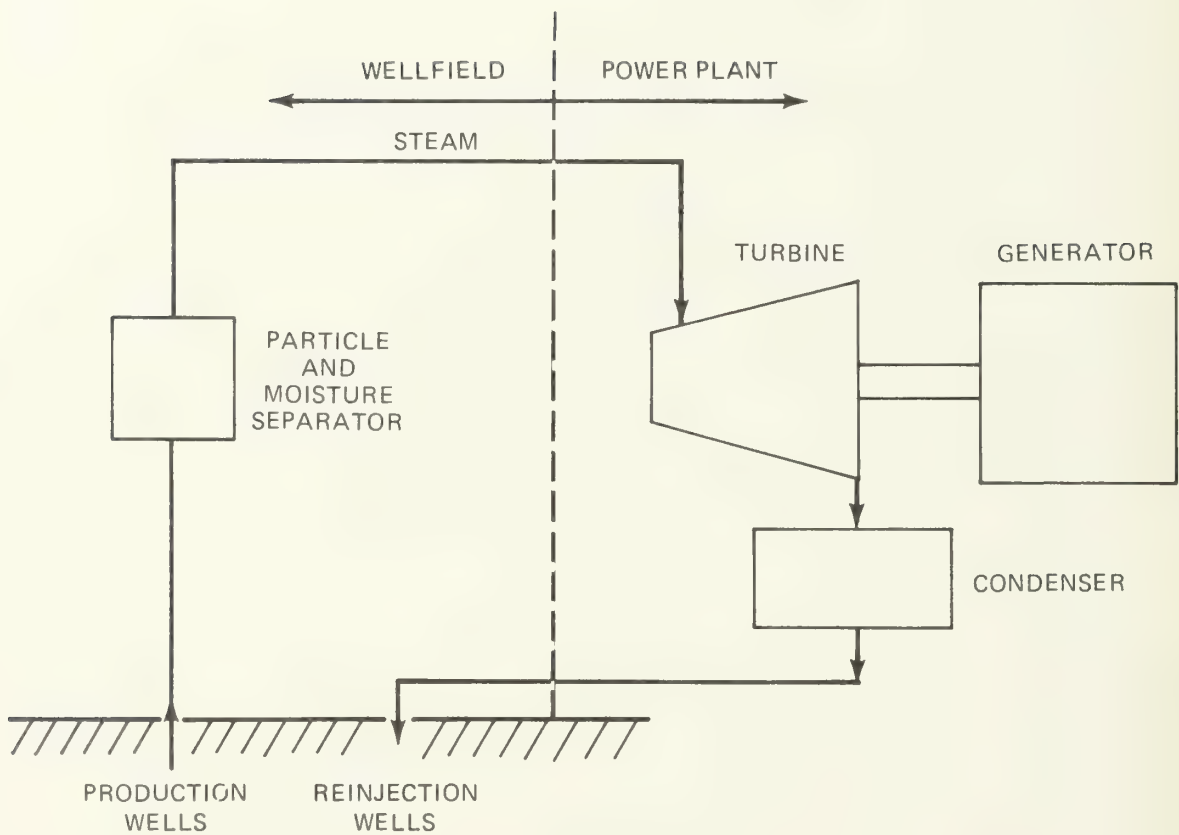


Figure 2-1 DIRECT STEAM PROCESS

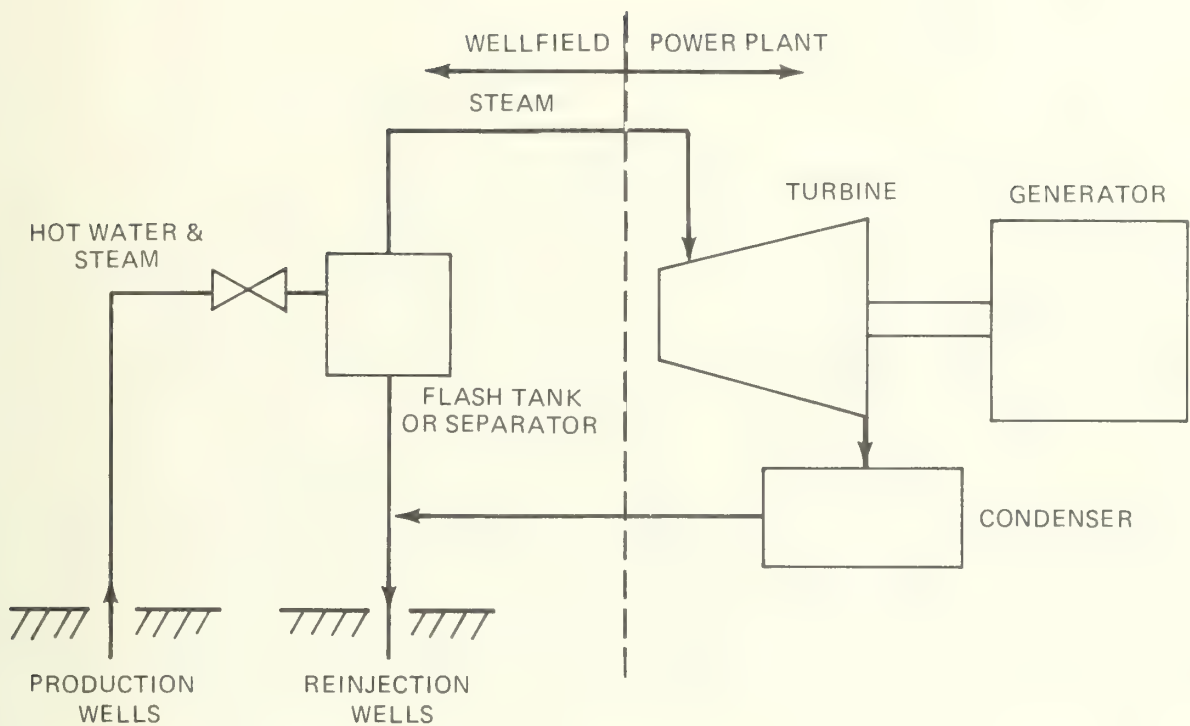


Figure 2-2 FLASHED STEAM PROCESS – SINGLE FLASH

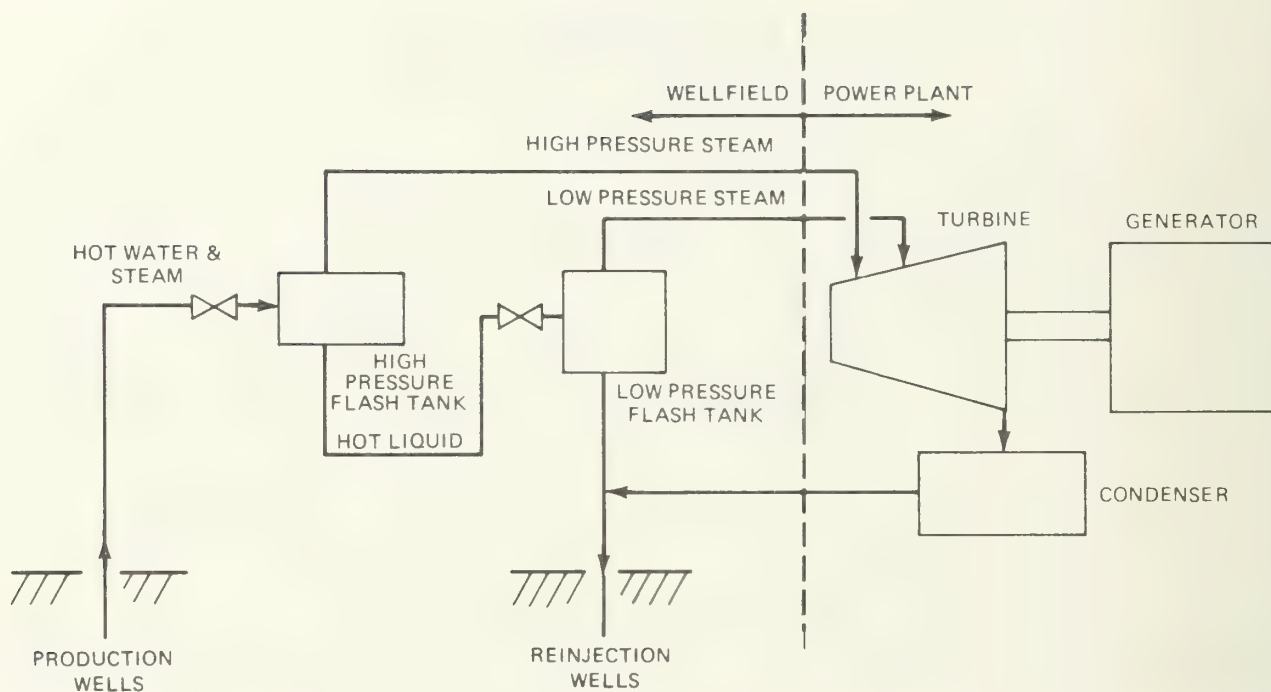


Figure 2-3 FLASHED STEAM PROCESS – DOUBLE FLASH

supply line from the steam separators or flash tanks and the condensate return line to the reinjection well. Commercial flashed steam plants of up to 55 MWe are operating in a number of countries.

Most flashed steam power plants use one flash stage, as shown in Figure 2-2. The turbine, condenser, and wellfield interface points are similar to those of the direct steam process plant discussed above. However, some of the more recent plants use two flash stages with steam being supplied to the turbine at two different pressures, as shown in Figure 2-3. This requires a turbine configuration with two steam inlet nozzles, one at a high pressure and one at a lower pressure. Such a machine is commonly called an admission turbine, a reference to the additional steam admission nozzle. The condenser is similar to those of the single flash and direct steam designs discussed above. The interfaces with the wellfield are the two steam lines and the reinjection line.

The double flash process uses the geothermal hot water more efficiently and requires fewer wells, but it also requires more attention to hot water chemistry because mineral scale formation in the wellfield facilities may be more severe as the geothermal water is flashed to lower temperatures.

### 2.1.3 Balance of Plant

In all the steam expansion plants described above, the heat given up by the condensation of the turbine exhaust steam is rejected to the atmosphere by means of a circulating water system and a cooling tower. A large flow of water (approximately 40 times the turbine steam flow) circulates continuously between the condenser and the cooling tower. Condensation of the steam from the turbine warms the circulating water by approximately 25°F, and the circulating water is then cooled the same amount by partial evaporation in the cooling tower. A 50 MWe plant would typically evaporate 1400 to 1700 gpm of cooling water. This makeup water for a geothermal power plant is often supplied by condensed turbine

exhaust steam that is mixed with the circulating water in the hot water return line. This offsets the loss of circulating water through evaporation in the cooling tower and also produces a net accumulation of circulating water amounting to 15 to 20 percent of the condensate. For a 50 MWe plant, the excess condensate remaining after cooling tower evaporation is typically 200 to 300 gpm. This excess water is usually returned to the wellfield for reinjection into the ground, carrying with it sufficient impurities to prevent further solids buildup in the circulating water system.

Other major systems include the electrical system, the control system, and the turbine building.

Several auxiliary plant systems, including the compressed air system, service water system, fire protection system, emergency diesel-generator system, and heating, ventilating and air conditioning systems are provided to support the main power production process.

#### 2.1.4 Processes Under Development

Power generation processes emerging from development to commercial status include the binary cycle and the two-phase expander, as described below. Small capacity units using these processes are currently being offered for commercial use by equipment manufacturers.

Binary Cycle. A binary cycle uses a working fluid heated by geothermal hot water, as shown in Figure 2-4. The working fluid is a halocarbon (e.g. Freon), a light hydrocarbon, or a mixture of light hydrocarbons. The main advantages of a binary cycle compared to a flashed steam process are that lower temperature resources can be used and no H<sub>2</sub>S abatement system is needed. The binary cycle is under development in Israel, Japan, and the United States. An 11 MWe plant is in operation at East Mesa, California. A 45 MWe binary demonstration plant is being constructed at Heber in the Imperial Valley of California, with initial operation expected in May 1985. In addition, a 7 MWe (net) binary plant, composed of two 3.5 MWe modules, is nearing commercial operation at Mammoth, California.

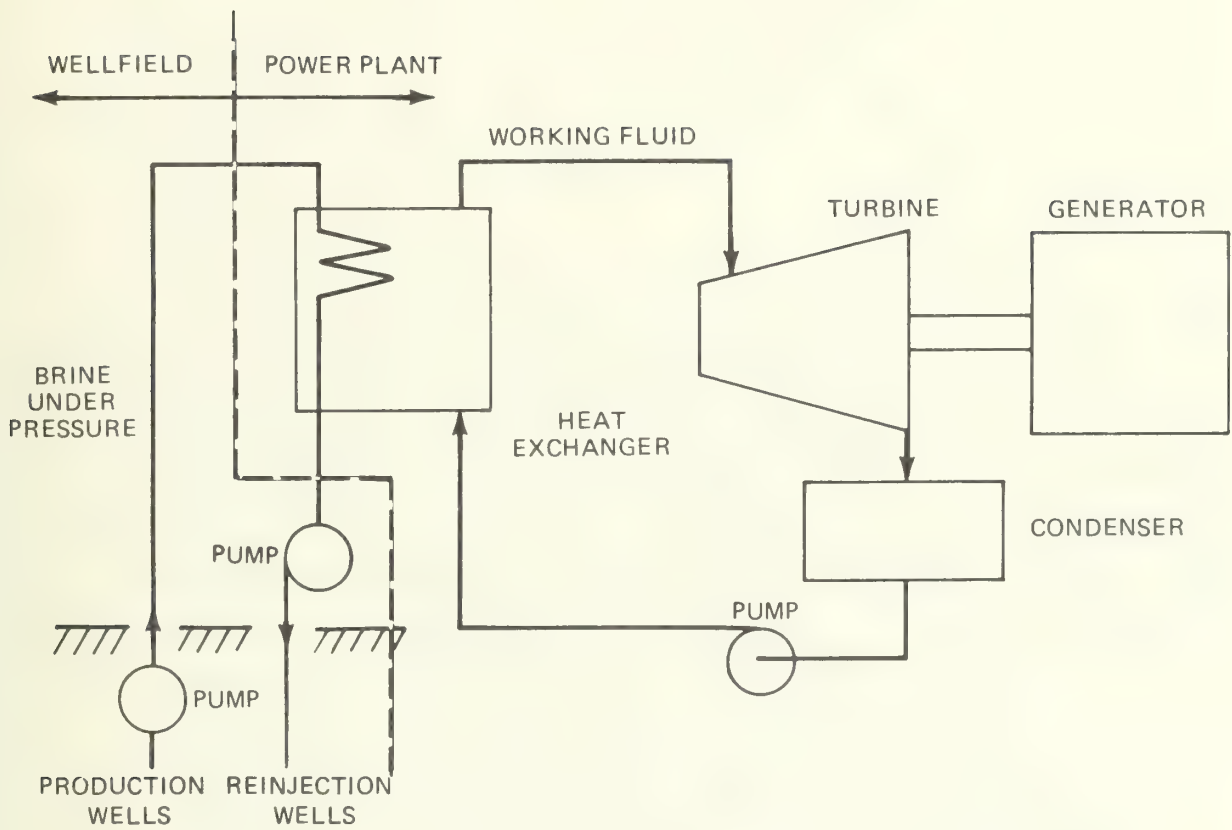


Figure 2-4 TYPICAL BINARY CYCLE

Two-Phase Expander. According to thermodynamic theory, the best hot water utilization would occur when the two-phase flow from a production well is expanded through a specially designed two-phase expander to generate power. The rotary separator turbine has been built in the United States in small units of up to 1 MWe, and has undergone tests at various hot water resource sites. Transamerica Delaval, Inc., the developer and principal manufacturer of the rotary separator turbine, is now aggressively marketing this device. Two units that combine with small conventional steam turbines to produce 9 to 14 MWe are to be installed by the end of 1986 at Desert Peak in Nevada and at Roosevelt Hot Springs in Utah.

## 2.2 GENERAL METHODS

The power plant cost data described in Section 1 were adjusted to reflect the costs for geothermal power plants without H<sub>2</sub>S abatement equipment and located in flat, open terrain. All these cost estimates were adjusted to price levels of September 1984 using the Handy-Whitman steam generation construction cost index. The updated data for each resource type, resource temperature, and plant type were then used to define a power-law correlation of power plant capital cost as a function of plant net capacity for the range from 10 to 100 MWe.

Table 2-1 lists the scope and exclusions for the geothermal power plant cost estimates addressed in Section 2. The magnitude of the exclusions ranges from possibly less than one percent of total facility cost for land costs, to several percent for owners engineering, administrative, and general costs. Power transmission lines beyond the plant site boundary may constitute a large fraction of the plant cost for some especially remote sites. Interest during construction and inflation after September 1984 are best handled as part of the economic calculations that are done by others to screen the geothermal resource sites.

Table 2-1

SCOPE AND EXCLUSIONS FOR POWER PLANT COST ESTIMATES

Scope Included

Turbine inlet valves and strainers  
Turbine and generator  
Condenser (surface type)  
Condensate pumps  
Cooling towers  
Circulating water pumps and piping  
Main transformer  
Switchyard  
Process piping  
Plant electrical equipment  
Instrumentation and controls  
Site preparation  
Turbine and control building  
Balance of plant systems  
Geothermal hot water-to-working fluid heat exchangers (binary only)  
Working fluid pumps (binary only)  
Construction labor  
Engineering, procurement, and construction management  
Indirect field costs (temporary construction facilities, miscellaneous construction services, construction equipment and supplies, field office, preliminary checkout and acceptance testing, startup, project insurance, and state and local taxes)

Exclusions

Land or land use costs  
Interest during construction  
Inflation after September 1984  
Owner's engineering, administrative, and general costs  
Research and development costs  
Permits and licenses  
Power transmission lines beyond the plant site boundary  
H<sub>2</sub>S abatement (treated separately in Section 2.6)

## 2.3 STEAM RESOURCES

### 2.3.1 Specific Methods

The logarithms of cost and net capacity for the power plants using steam resources were correlated by a least square fit to a straight line. This straight line for a log-log plot is a power-law correlation of cost and capacity.

### 2.3.2 Results

The cost data and the power-law correlation for geothermal power plants using steam resources similar to The Geysers are shown in Figure 2-5.

All cost estimates except those for plants numbered 4 and 8, in Table 1-1, are within +10 percent of the power-law correlation. The estimates for plants numbered 4 and 8 are within +35 percent; deviations of this magnitude in the estimates for individual plants are to be expected due to differences in resource conditions, site-specific conditions, regulatory requirements, and amount of engineering completed at the time of the estimate.

Since the data are for plants with capacities ranging from 5 to 110 MWe (net), this correlation applies over the desired range of 10 to 100 MWe (net) with no need for extrapolation.

The use of three significant figures in the power-law equation is for computational precision. It does not imply any particular expectation concerning accuracy. Throughout this report, three significant figure precision is used uniformly.

## 2.4 HOT WATER RESOURCES

### 2.4.1 Specific Methods

The cost data for geothermal power plants using hot water resources is sparse compared to that for steam resources. Therefore, the exponent in the power law for power plants using steam resources was assumed to apply

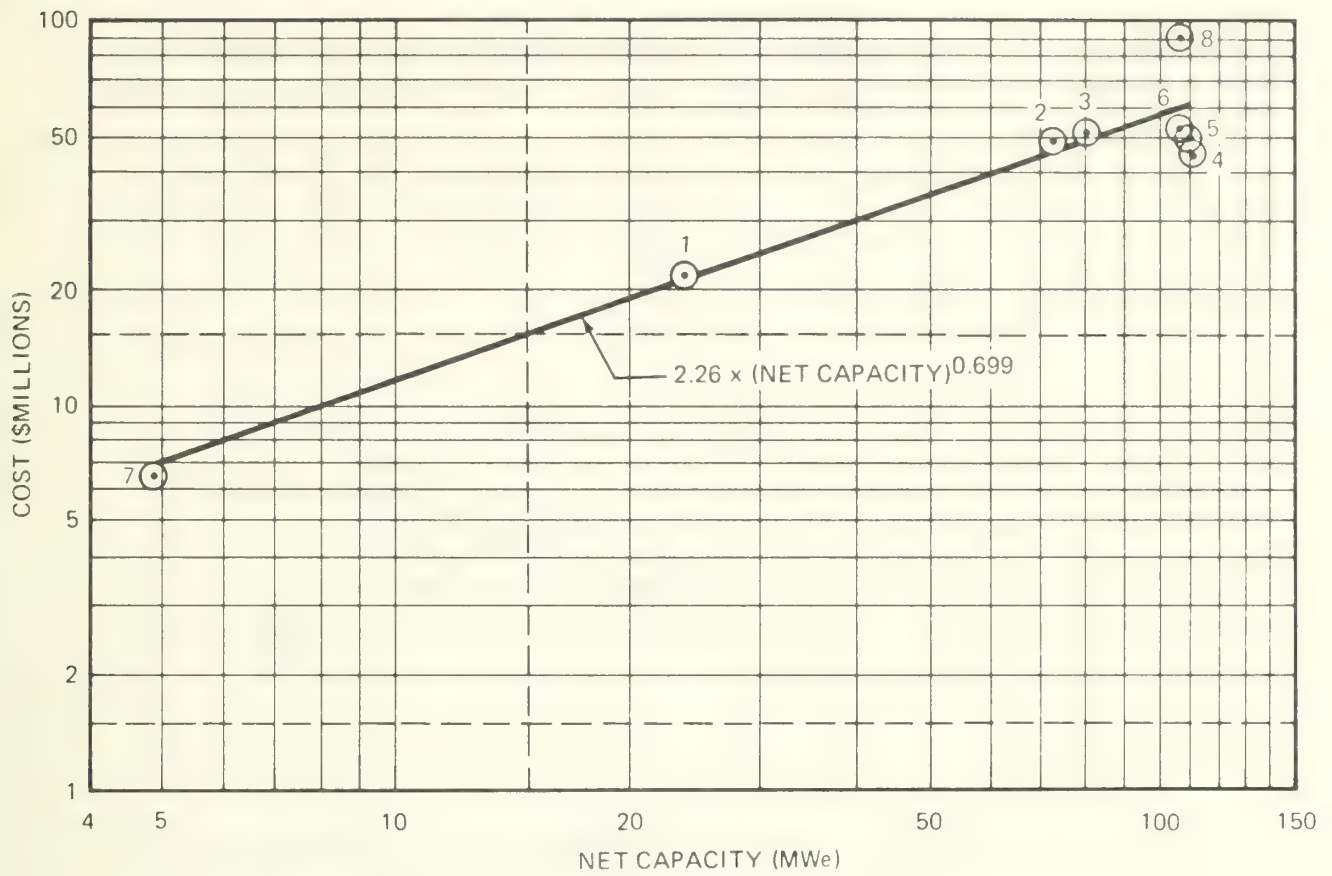


Figure 2-5 POWER PLANT CAPITAL COST,  
STEAM RESOURCE

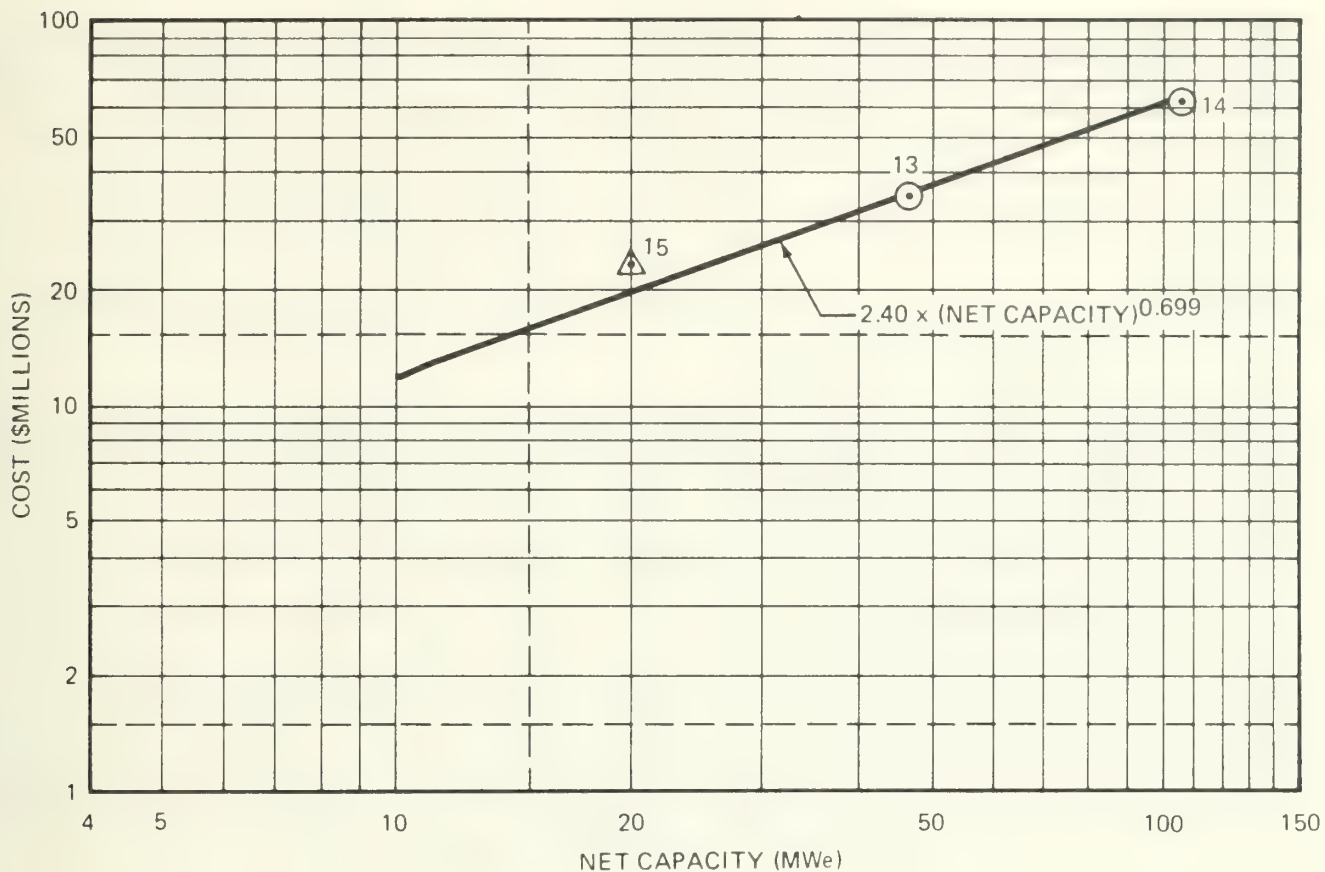
for all flashed steam plants. This is a reasonable expectation because the power plants are physically similar. The thermodynamic condition of the inlet steam is the fundamental difference between any two plants that use steam to drive a turbine. The log-log data for cost and capacity were fitted (by a least squares fit) to a straight line having the same slope as for the plants using a steam resource. Thus, the exponent in the power law is the same in every case, but the coefficient varies to fit the data in each situation.

Binary geothermal power plants are fundamentally different from direct steam and flashed steam plants; therefore, the correlation of cost and capacity may be different. The available cost estimates for binary systems were fitted to a power-law correlation, as described in Section 2.3.1.

#### 2.4.2 Results

Flashed Steam Plants. Figures 2-6 through 2-10 show the cost data and the power-law correlation for geothermal power plants using flashed steam processes as follows:

- o 530°F, Single flash - Figure 2-6. The two estimates (for plants numbered 13 and 14) used to define this equation are within +3 percent of the costs estimated by the equation. The cost estimate for plant numbered 15 was not used in the correlation because it includes costs for wellfield surface facilities that could not be quantified; this estimate is shown in Figure 2-6 as a reference point.
- o 530°F, Double flash - Figure 2-7. The two estimates (for plants numbered 19 and 20) used to define this equation are within +10 percent of the costs estimated by the equation.
- o 420°F, Single flash - Figure 2-8. The two estimates (for plants numbered 16 and 17) used to define this equation are within +4 percent of the costs estimated by the equation. The cost estimate for plant numbered 18 was not used in the correlation because it includes some costs for field development that could not be quantified with the available data.



**Figure 2-6 POWER PLANT CAPITAL COST,  
530°F HOT WATER RESOURCE,  
SINGLE FLASH**

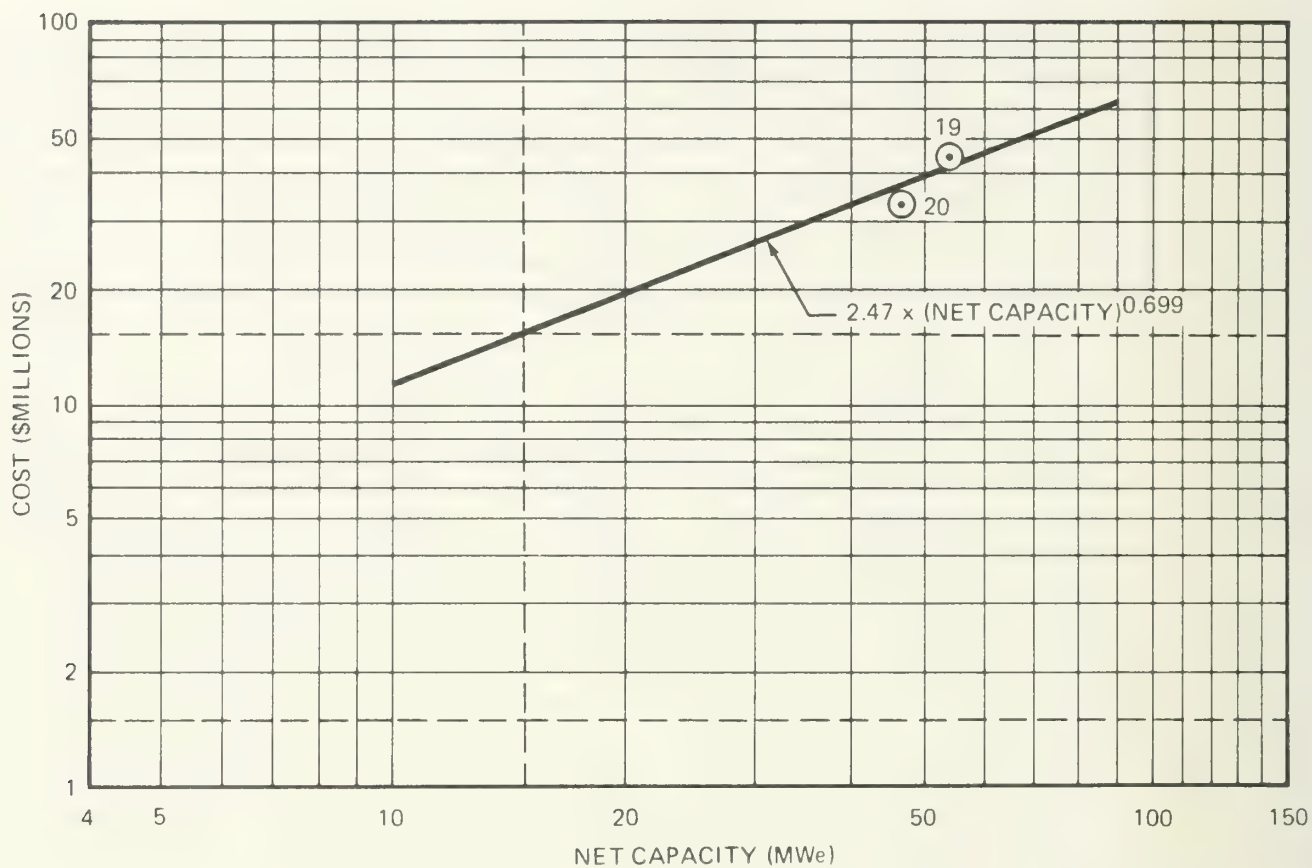
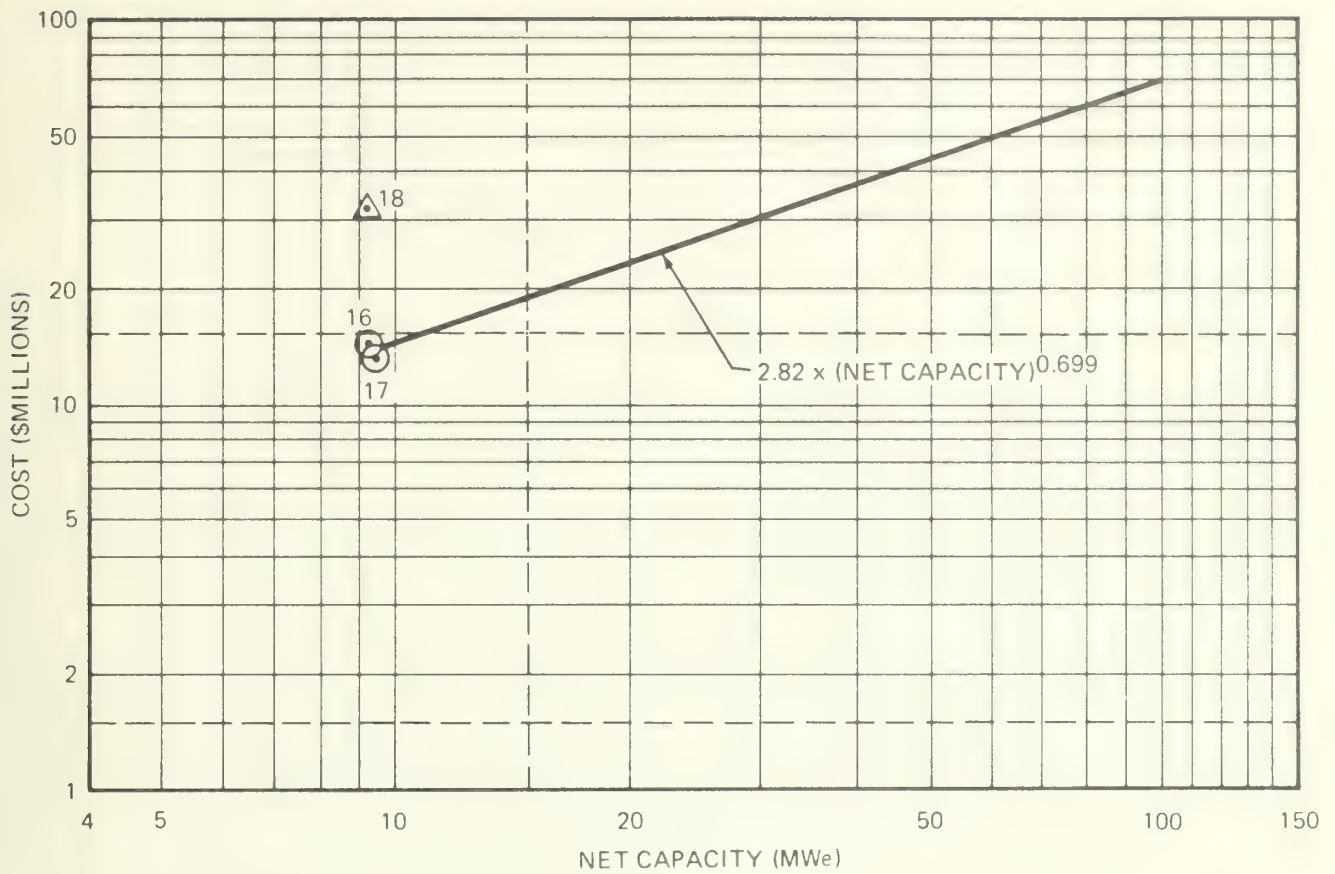


Figure 2-7 POWER PLANT CAPITAL COST,  
530°F HOT WATER RESOURCE,  
DOUBLE FLASH



⊙ DATA USED IN CORRELATION

△ COST ESTIMATE NOT USED IN CORRELATION  
BECAUSE SCOPE IS DIFFERENT. SEE TEXT  
FOR EXPLANATION.

Figure 2-8 POWER PLANT CAPITAL COST,  
420°F HOT WATER RESOURCE,  
SINGLE FLASH

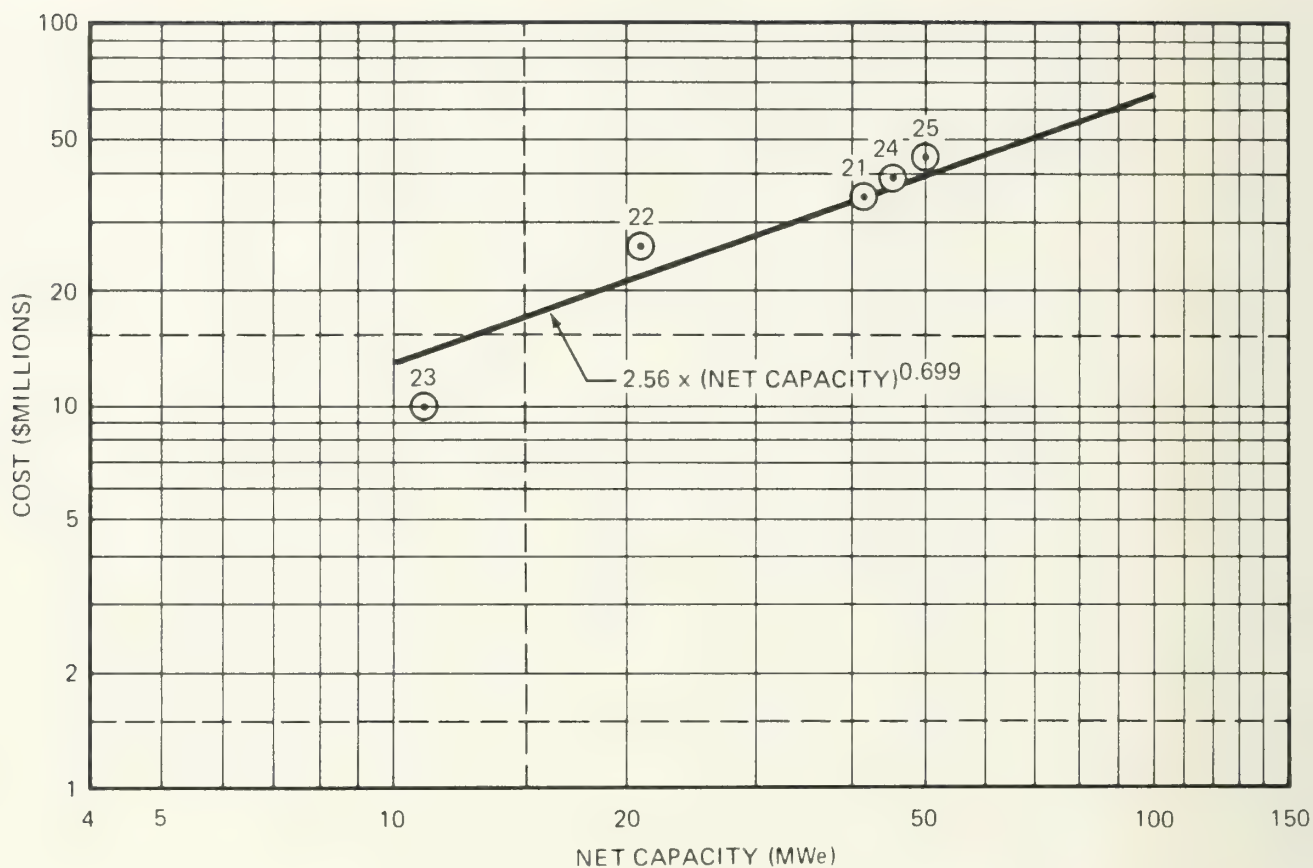


Figure 2-9 POWER PLANT CAPITAL COST,  
420°F HOT WATER RESOURCE,  
DOUBLE FLASH

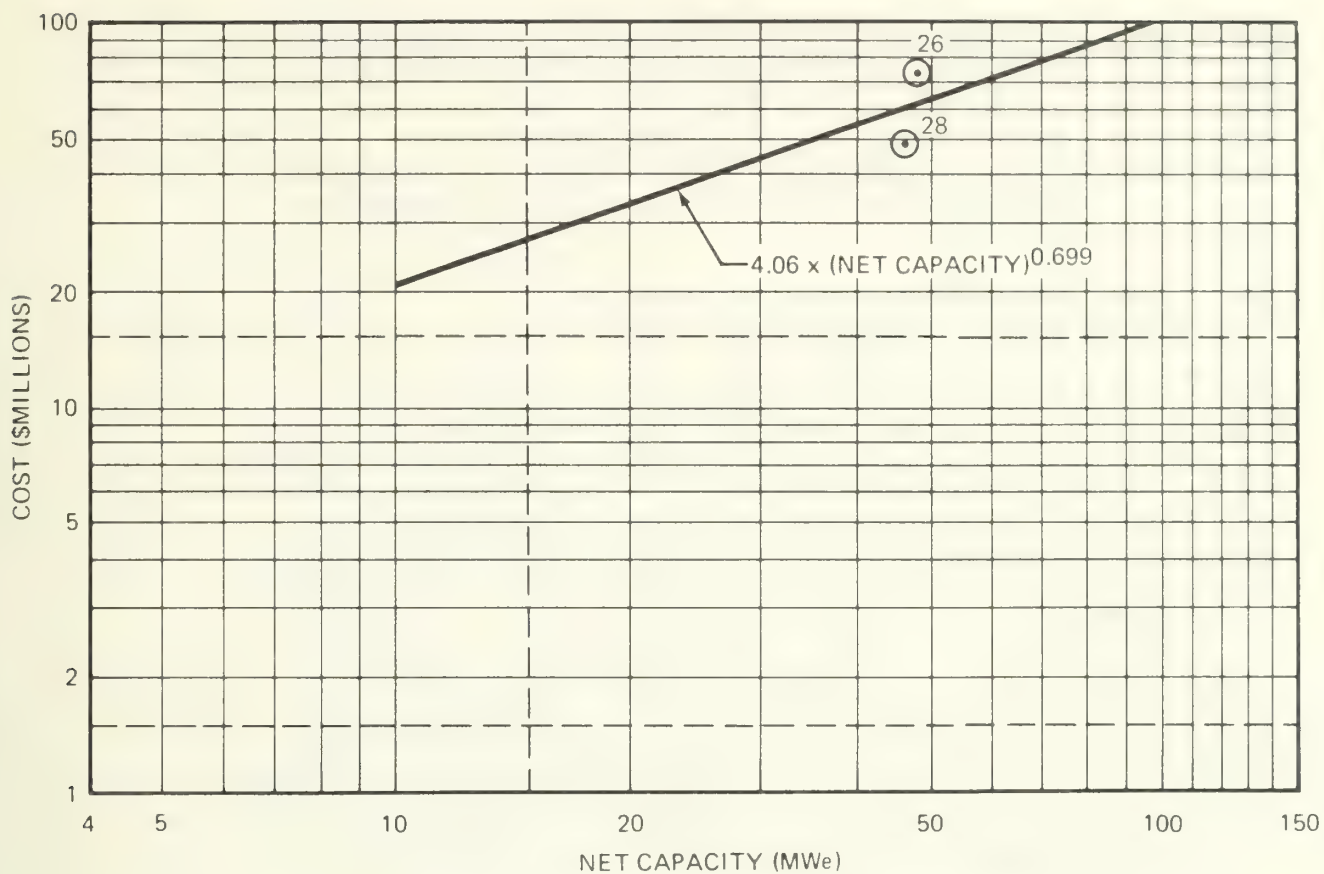


Figure 2-10 POWER PLANT CAPITAL COST,  
350°F HOT WATER RESOURCE,  
DOUBLE FLASH

- o 420°F, Double flash - Figure 2-9. All cost estimates except for the plant numbered 23 are within +20 percent of the power-law correlation.
- o 350°F, Double flash - Figure 2-10. The two cost estimates are within +20 percent of the power-law correlation.

350°F, Binary. Figure 2-11 shows the cost data and power-law correlation for geothermal binary power plants using a 350°F hot water resource.

All the cost estimates, except for plant numbered 32, are within +30 percent of the power-law correlation. The cost estimate for plant numbered 32 is 39 percent greater than implied by the power-law correlation.

The value of the exponent (1.015) in the power-law equation is so near unity that the cost for binary plants appears to be virtually proportional to net capacity. This would indicate that there is no "economy of scale" as is the case for steam power plants. This may result from the "demonstration plant" status for plant numbered 29, the Heber Binary Plant. As additional cost details become available for the Heber plant, they should be analyzed to determine whether the costs for this demonstration plant apply directly to a commercial plant of the same capacity or whether there are one-time costs resulting from the demonstration plant program.

An alternative cost relationship for binary plants can be developed using the estimate for plant numbered 31, the Mammoth (California) plant. The 3.5 MWe (net) modules could be replicated to produce a facility with a larger capacity. If that were done, the power plant cost would be proportional (in 3.5 MWe increments) to capacity as follows:

$$\text{Cost} = 1.543 \times \text{Net Capacity}$$

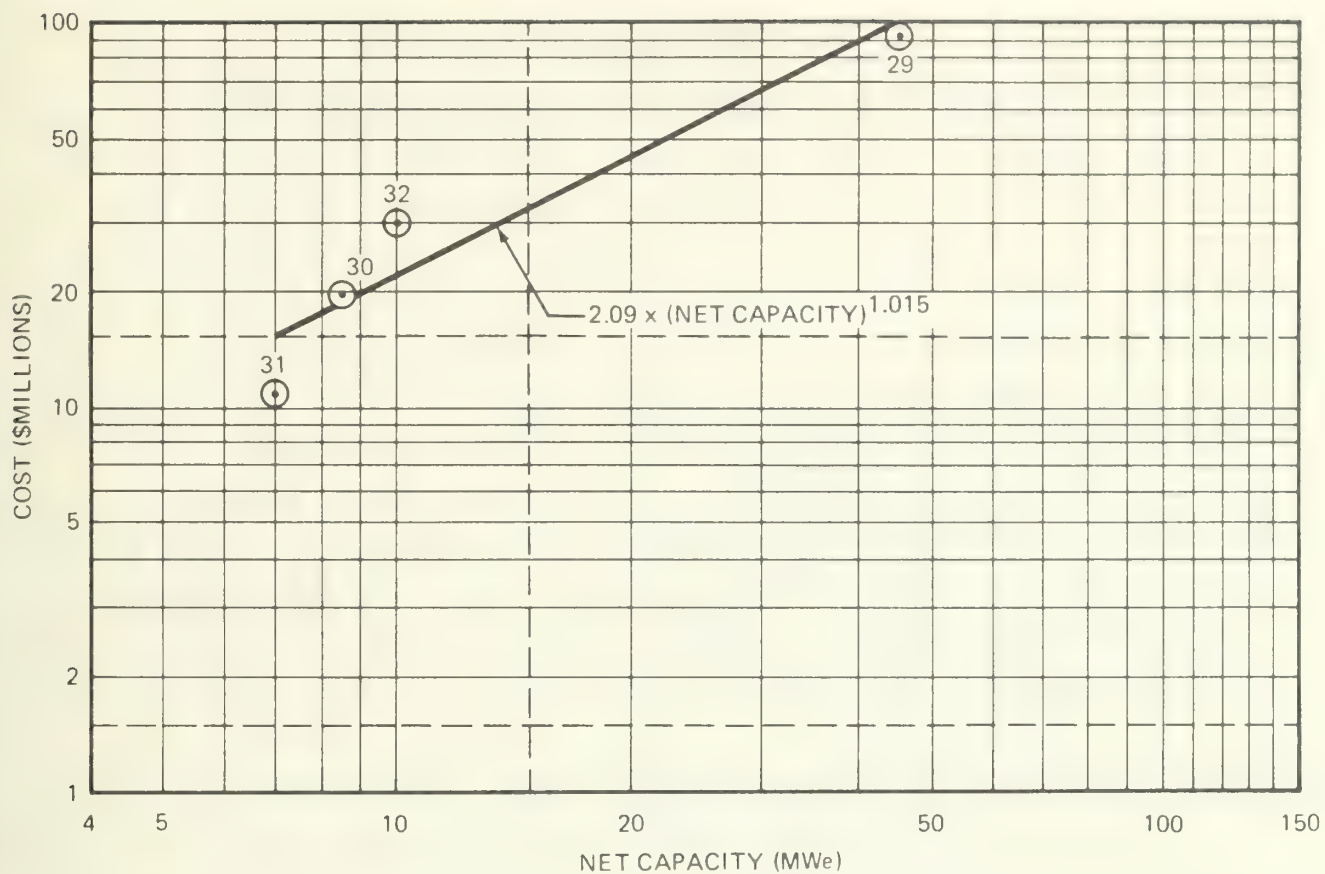


Figure 2-11 POWER PLANT CAPITAL COST,  
350°F HOT WATER RESOURCE,  
BINARY

## 2.5 TYPICAL PLANT PERFORMANCE

For both technical and economic reasons, geothermal power plants are better suited to serving the base load, rather than the peaking capacity requirements of an electrical system. Traditionally, geothermal power plants have been designed to ensure a desired net output year round; however, the floating power approach has received consideration in the past few years. With the floating power approach, geothermal fluid flow is held constant and the power plant generates more power for low ambient temperature than for the hot conditions on summer afternoons. With either approach, the data in Table 2-2 represent typical average figures for gross, auxiliary, and net power, and for geothermal fluid rate per kW of net power generated. Various technical papers from the geothermal literature and design reports from Bechtel files were used as the sources of these data.

For the direct steam and flashed steam plants, the auxiliary power consumption ranges from 4.6 to 10.0 percent. However, the auxiliary power for a binary plant is greater than 30 percent. This is largely due to the power needed to pump the binary working fluid from the condenser pressure to that of the evaporator. This relatively large auxiliary power consumption also accounts for equal geothermal fluid rate for the binary and double flash plants using a 350°F resource, even though the binary plant is often touted as being more efficient.

## 2.6 HYDROGEN SULFIDE ABATEMENT SYSTEM

Geothermal fluids usually contain hydrogen sulfide ( $H_2S$ ) concentrations up to several hundred parts per million for specific resources. In steam and flashed steam power plants,  $H_2S$  would be discharged to the atmosphere unless it is abated. If the unabated  $H_2S$  discharge would violate air quality regulations, a system to remove the  $H_2S$  would be needed to treat the gases emitted from the power plant.

Table 2-2

## TYPICAL PERFORMANCE FOR GEOTHERMAL POWER PLANTS

<u>Item</u>	<u>Performance</u>						
	<u>Direct Steam</u>	<u>530°F SF</u>	<u>530°F DF</u>	<u>420°F SF</u>	<u>420°F DF</u>	<u>350°F DF</u>	<u>350°F Binary</u>
Gross Generator Output <sup>(a)</sup>	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total Auxiliary Power and Transformer Losses <sup>(a)</sup>	<u>6.1</u>	<u>6.2</u>	<u>4.6</u>	<u>7.6</u>	<u>5.8</u>	<u>10.0</u>	<u>31.1</u>
Net Power Output <sup>(a)</sup>	93.9	93.8	95.4	92.4	94.2	90.0	68.9
Typical Geothermal Fluid Rate <sup>(b)</sup>	18 <sup>(c)</sup>	68 <sup>(d)</sup>	54 <sup>(d)</sup>	128 <sup>(d)</sup>	100 <sup>(d)</sup>	171 <sup>(d)</sup>	171 <sup>(e)</sup>

SF - Single flash

DF - Double flash

(a) Percent of gross output

(b) Pounds per kilowatt hour net (lb/kWh net)

(c) Steam

(d) Two-phase mixture of steam and hot water

(e) Hot water

The best available control technology for  $H_2S$  abatement is the Stretford system currently used at The Geysers. This system selectively removes  $H_2S$  from the noncondensable gases drawn from the condenser. A secondary abatement system for removing  $H_2S$  from the condensate has been required for some of the plants at The Geysers to meet air quality requirements.

To obtain an estimate for the cost of typical  $H_2S$  abatement systems, data for The Geysers plus an estimate for the Baca plant (plant numbered 13) were plotted and correlated as shown in Figure 2-12.

This estimate might be considered typical for The Geysers; however, costs for specific plants may be considerably different. The cost estimates plotted in Figure 2-12 are as low as one third and as high as almost three times the typical value. Much of the explanation for this is that the noncondensable gas (including  $H_2S$ ) concentration is not uniform over The Geysers resource; therefore, abatement costs are different. Noncondensable gas varies from 0.2 to 1.9 percent, and  $H_2S$  ranges from 172 to 915 ppm by weight in the steam.

In summary, the typical cost value from the correlation equation may be used for economic screening where the actual  $H_2S$  conditions are not yet known. However, the actual cost for  $H_2S$  abatement equipment for a particular plant may be considerably higher or lower.

## 2.7 BIPHASE POWER MODULES

The Biphase power module uses a rotary separator turbine (RST) which is a recent development in prime movers. The RST expands a two-phase mixture of steam and liquid water to produce power and in doing so separates the two phases. The steam emerging from the RST can be used to drive a conventional steam turbine. Since the Biphase power modules are fundamentally different from either the flashed steam or the binary power plants, they are discussed in this separate section rather than being considered in Section 2.4 with the flashed steam and binary plants.

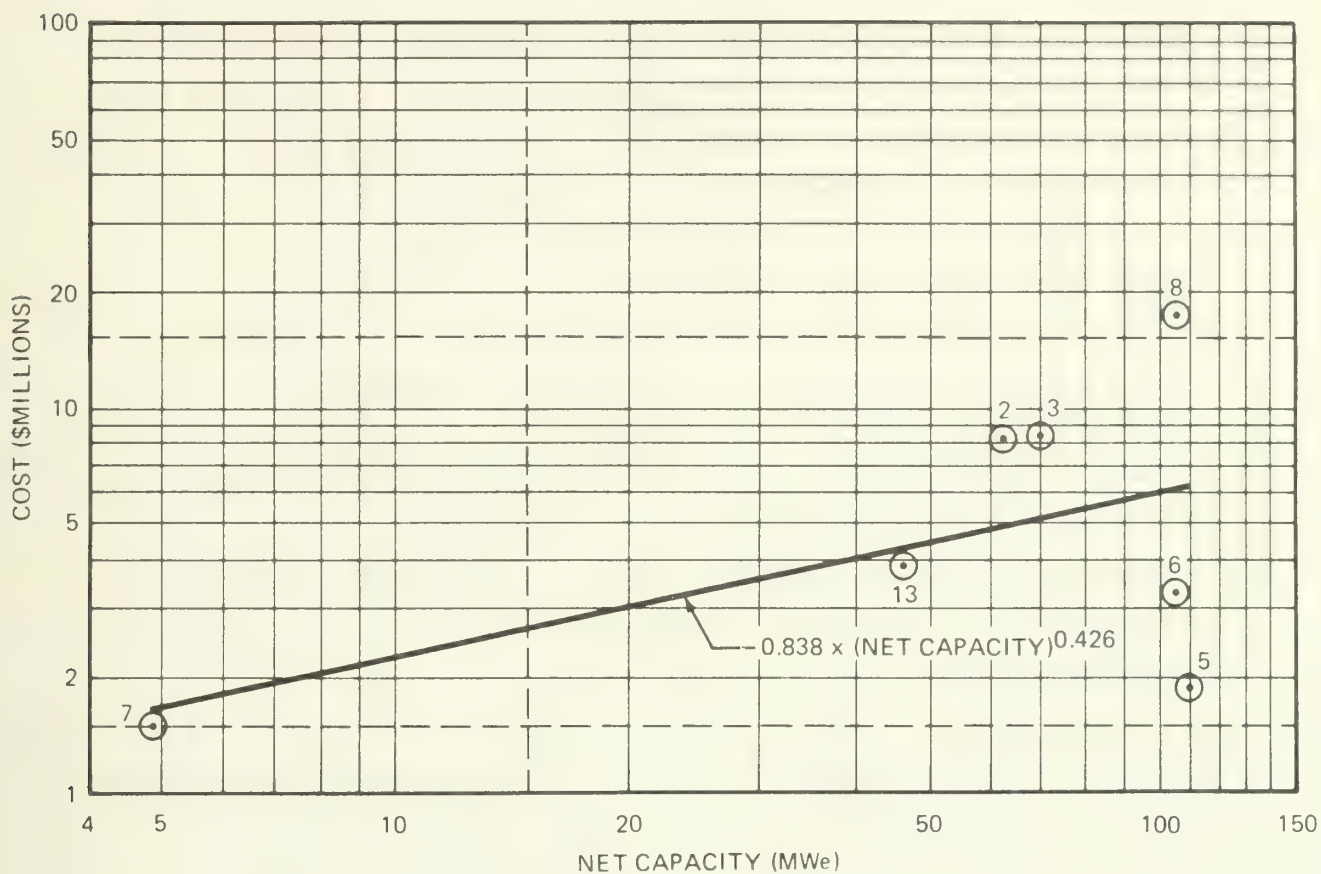


Figure 2-12 CAPITAL COST OF HYDROGEN  
SULFIDE ABATEMENT SYSTEM

The configuration (Figure 2-13) for the commercial geothermal power plants at Roosevelt Hot Springs, Utah and at Desert Peak, Nevada uses a steam turbine that has steam admitted at two pressures similar to the turbine for a double flash process. Two-phase flow from a production well enters a separator tank and the exiting steam fraction flows to the high pressure inlet of the steam turbine. The liquid from the separator tank is then expanded in the RST where power is produced and low pressure steam is separated. An RST can be designed to pressurize the liquid for reinjection; therefore, reinjection pumps are not needed. The steam exhausting from the steam turbine is condensed in either a direct contact or a surface condenser; the choice of the higher-cost surface condenser is usually dictated by requirements for hydrogen sulfide abatement. Heat is rejected by an evaporative cooling tower that uses steam condensate for makeup water.

The current Biphasic design approach is to build packaged power generating modules that incorporate the largest model of the RST plus a steam turbine and generator. The modules are designed for the specific geothermal reservoir conditions and are capable of generating from 4.5 MWe (net) for a resource temperature of 350°F to 18.2 MWe (net) for 530°F.

Capital cost estimates and performance data furnished by Transamerica Delaval, the manufacturer of the RST, are given in Table 2-3. An important assumption for the estimates is that one production well is used in each case or that all the production wells are drilled from one production island; therefore, wellfield production surface facilities are minimized. Along with the cost and performance information, Transamerica Delaval emphasizes the following caveat that is inherent in generic cost estimates. "We find it difficult to supply generalized estimates which can be used for "apples-to-apples" comparisons. Prices for modular plants are strongly influenced by whether or not the system engineering is in hand, and by whether or not multiple orders are placed. Price variations on the order of plus or minus 35 percent would not be unusual."

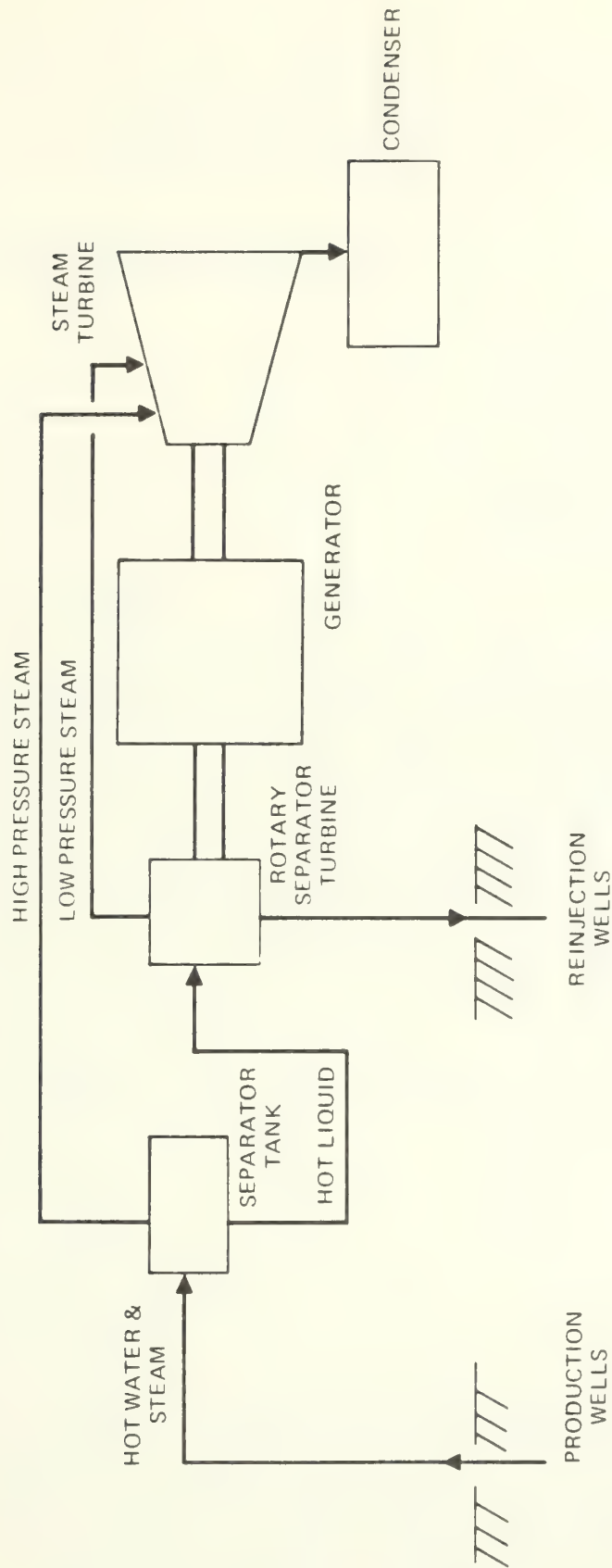


Figure 2-13 BIPHASE PROCESS

Table 2-3

CAPITAL COST ESTIMATES AND PERFORMANCE  
DATA FOR BIPHASE POWER MODULES<sup>(a)</sup>

<u>Item</u>	<u>Resource Temperature</u>		
	<u>350°F</u>	<u>420°F</u>	<u>530°F</u>
Module Capacity - MWe (net)	4.50	9.80	18.20
Cost of Power Plant and Wellfield Production Surface Facilities <sup>(b)</sup> - \$million	6.53	10.58	15.83
Cost of Wellfield Reinjection Surface Facilities - \$million			
o Low Cost	0	0	0
o Probable Cost	0.22	0.20	0.22
o High Cost	0.47	0.42	0.46
Well Flow Required - lb/hr	600,000	900,000	1,200,000
Auxiliary Power - MWe	0.55	0.75	0.90
Gross Capacity - MWe (gross)	5.05	10.55	19.10

(a) Based on estimates furnished by Transamerica Delaval.

(b) One production well is required or all production wells are drilled from one production island.

Operating and maintenance costs can be estimated as discussed in Sections 3 and 5 for the power plant and wellfield facilities respectively. One operating staff could be expected to operate up to seven generating units. Wellfield operation is in addition as discussed in Section 5.1. The term for pumping cost in Section 5.4 should be set equal to zero since the RST would pressurize the liquid for reinjection.

Interest during construction at an assumed interest rate of 10 percent is included in the estimates of Table 2-3. The construction period for a module is about 14 months, and the time from the centroid of expenditures to the date of commercial operation is 0.25 to 0.33 years.

## 2.8 ORMAT POWER UNITS

The Ormat power unit is based on the binary cycle (see Section 2.1.4 for a description of the binary cycle) and is being marketed as a standardized package having 1200 kWe (gross) per unit. For a specific resource, the units would be cascaded to match the resource temperature and installed as multiple trains to produce the desired power capacity. Figure 2-14 shows an example of the configuration of Ormat units needed to produce 10 MWe (net); the example is for a resource temperature of 350°F.

Performance data furnished by Ormat Systems Inc. are given in Table 2-4. In each case, the power output and auxiliary power are expected to be as follows:

- o 12 MWe gross
- o 2 MWe auxiliary power
- o 10 MWe net output

For each case, the total power plant cost estimated by Ormat is \$14 million; Ormat has indicated an intention to furnish power plants at virtually the same cost per net power output over the temperature range from 250 to 350°F. This includes an evaporative cooling system and connection to a high-voltage transmission line.

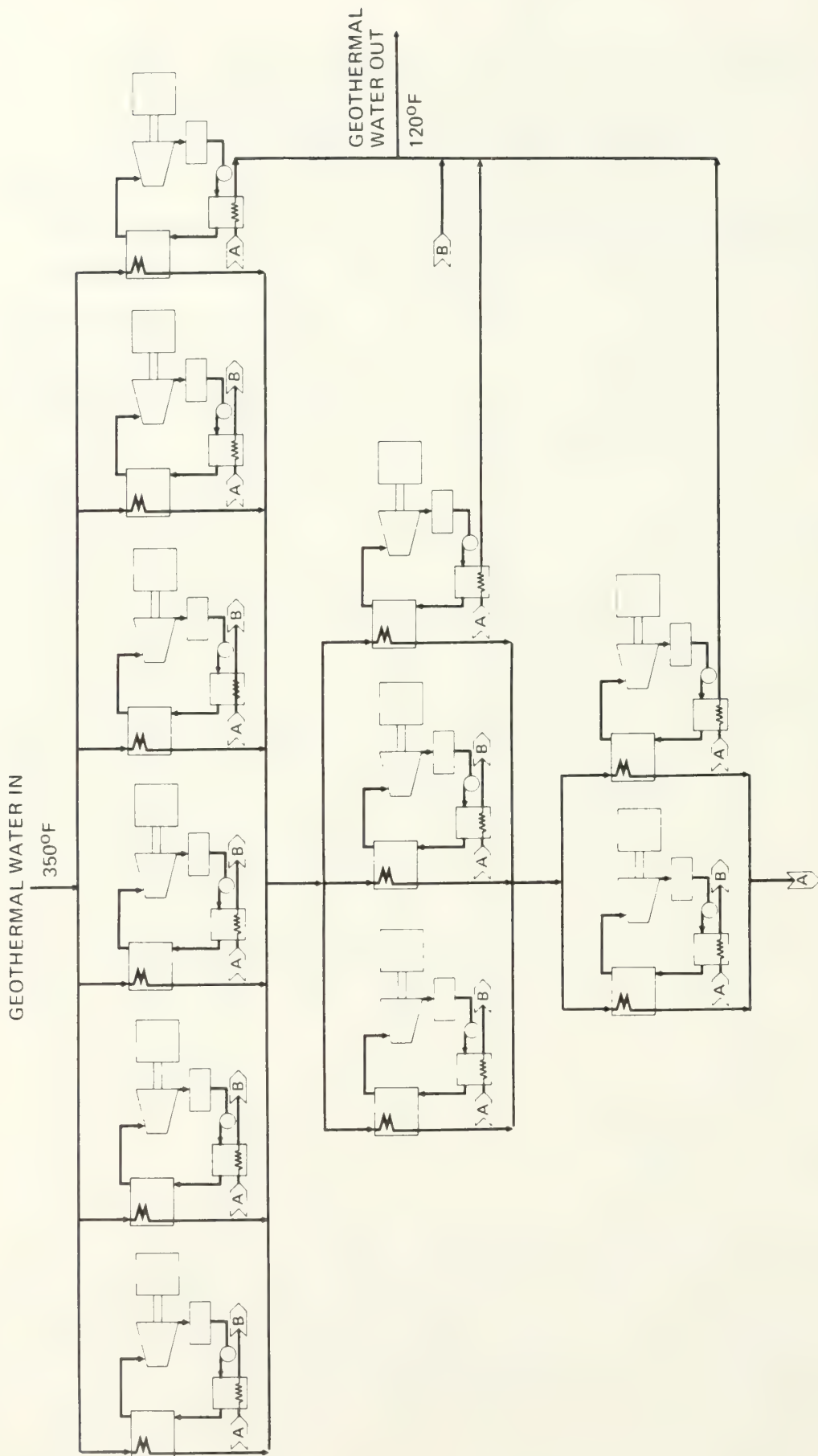


Figure 2-14 EXAMPLE OF CONFIGURATION OF ORMAT UNITS TO PRODUCE 10 MWe (NET)

Table 2-4

PERFORMANCE OF ORMAT UNITS  
10 MWe NET OUTPUT

<u>Item</u>	<u>Resource Temperature</u>		
	<u>350°F</u>	<u>300°F</u>	<u>250°F</u>
Temperature of Geothermal Water Out (°F)	120	140	155
Flow Rate of Geothermal Water (10 <sup>6</sup> lb/hr)	1.55	2.40	4.50
Number of Units	11	13	14
Number of Cascaded Temperature Levels	3	3	2



### Section 3

#### OPERATING AND MAINTENANCE COSTS FOR GEOTHERMAL POWER PLANTS

The annual operating and maintenance (O&M) costs for geothermal power plants consist of the following:

- o Operating labor includes the wages and labor burden for the operators and technicians who monitor the power plant operation and make the adjustments and minor repairs needed to operate the power plant under varying load and process conditions.
- o Maintenance costs are for the labor and materials needed to maintain the power plant.
- o Overhead charges are for administrative and support labor directly connected with the power plant operation and maintenance.

These components of the annual O&M costs are estimated below using an approach recommended by the Electric Power Research Institute (EPRI) (Ref. 1-1).

##### 3.1 OPERATING LABOR

For geothermal power plants in the range of 10 to 100 MWe, the number and type of personnel for operating a plant is virtually the same regardless of capacity. A small plant has the same number of systems as a large plant, and the complexity of the systems is similar.

On the other hand, experience at The Geysers has demonstrated that one operating crew can operate multiple plants. PG&E operates all its generating units from one central control location. Lower operating labor cost per kWh of electric energy can be achieved by having one operating crew operate several plants built at one resource. It appears reasonable to expect one crew to operate up to six steam or flashed steam units or four binary units.

For this report, an operating crew of a size appropriate for a power plant in the 10 to 100 MWe range has been defined, and the annual cost for employing the operating personnel was calculated. The operating crew is assumed to be composed of four chief operators (one for each weekly shift), five operators, and two electro/mechanical technicians.

A wage rate of \$15 per hour is assumed for operators and technicians. This rate is in agreement with a December 1983 advertisement for operators placed by the Sacramento Municipal Utilities District (Ref. 3-1). Chief operators are assumed to earn an average of 20 percent more than operators. Labor additives for FICA, holidays, sick leave, etc. are calculated as 35 percent of wages. The total operating labor cost for the personnel described above equals \$497,000 per year.

### 3.2 MAINTENANCE

In accordance with the EPRI procedure for calculating O&M costs, the annual maintenance costs for the power plant are estimated as a percentage of the installed capital cost. The appropriate percentage varies widely depending on the nature of the processing conditions and the type of design; typical ranges are shown in Table 3-1.

For low and probable cost situations, a maintenance cost equal to 3 percent of power plant capital cost is appropriate. For high cost situations (usually caused by greater corrosion), annual maintenance costs equal to 5 percent of capital cost might be incurred.

### 3.3 OVERHEAD CHARGES

The overhead charges for administrative and support labor are assumed to equal 30 percent of the costs for operating and maintenance labor as recommended by EPRI. Maintenance labor is assumed to account for 40 percent of the annual maintenance costs; the expense for maintenance materials accounts for the remaining 60 percent.

Table 3-1

TYPICAL RANGES OF ANNUAL MAINTENANCE COSTS  
AS A PERCENTAGE OF CAPITAL COSTS

<u>Type of Processing Conditions</u>	<u>Annual Maintenance Costs as a Percentage of Capital Costs</u>
Corrosive and abrasive slurries	6 to 10 (and higher)
Severe (solids, high pressure, and temperature)	4 to 6 (and higher)
Clean (liquids and gases only)	2 to 4
General facilities and steam electrical systems	1.5 to 3

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Source: Reference 1-1

### 3.4 POWER PLANT O&M COSTS

The equation for estimating annual power plant O&M costs can be reduced from three additive terms to two by combining the two components of the overhead charges with the operating labor and maintenance cost terms as follows:

$$\text{Annual O\&M cost} = \text{Operating labor cost} + \text{maintenance cost} + 0.3 \times (\text{operating labor cost} + \text{maintenance labor cost})$$

$$\text{Annual O\&M cost} = 1.3 \times \text{operating labor cost} + (1.3 \times 0.4 + 0.6) \times \text{maintenance cost}$$

$$\text{Annual O\&M cost} = 1.3 \times \text{operating labor cost} + 1.12 \times \text{maintenance cost}$$

If the operating crew operates multiple plants, the operating labor cost should be divided by the number of plants.



## Section 4

### CAPITAL COSTS FOR WELLFIELD SURFACE FACILITIES

#### 4.1 DESCRIPTION OF WELLFIELD SURFACE FACILITIES

##### 4.1.1 Gathering System

The gathering system is the piping that transports the geothermal fluids from the wells to the power plant. For a steam resource, the gathering system includes separators at the production wellheads to remove solid particles and small quantities of liquid that sometimes accompany the steam or that form by condensation in the piping.

For a hot water resource producing a mixture of steam and hot water at the wellhead, the steam separation and flash equipment can be located near the production wells, with steam piping to the power plant, or it can be located near the power plant. In the latter case, both steam and liquid are piped to the power plant as a two-phase mixture. An intermediate type of system involves the transport of the two-phase flow from several wells to satellite steam-separation stations. Steam is then manifolded in pipes for delivery to the power plant.

For a binary power plant using a hot water resource, the gathering system begins with downhole pumps in the production wells. These pumps are installed deep enough to pump only liquid with no free gas or steam. After the hot water is pumped to the surface under enough pressure to maintain liquid flow, the hot water lines from all the wells are manifolded together, and the aggregate flow is piped to the power plant.

##### 4.1.2 Steam Separation and Flash Equipment

The type of equipment used in the wellfield to convert the hot geothermal fluid to clean, dry steam suitable for admission to a turbine varies with the nature of the resource. For a steam resource, the wellhead particle

and moisture separators mentioned above are supplemented by additional moisture removal equipment at the delivery point to ensure that dry steam flows to the power plant. For a hot water resource, a "wellhead" separator may be used to control wellhead pressure and separate the two phases for flow measurement. One or two stages of flash vessels are used to generate steam in the single-flash and double-flash processes, respectively. Each stage of steam flashing uses a moisture separator to condition the steam for delivery to the power plant. Disposal of the geothermal liquid remaining after the final stage of steam flashing is by reinjection or by discharge to a surface body of water.

#### 4.1.3 Binary Cycle Wellfield Equipment

When a binary cycle is used with a liquid resource, the wellfield production facilities consist of a downhole pump for each production well and a surface gathering system that delivers hot geothermal liquid to the power plant. After passage through the water-to-working-fluid heat exchanger in the power plant, the geothermal fluid is returned to the wellfield for reinjection.

#### 4.1.4 Reinjection Equipment

If the wellfield operator reinjects the liquid geothermal fluid, the wellfield surface facilities include a set of reinjection pumps and a piping network to transport the fluid from the flash vessels or heat exchangers to the reinjection wells.

### 4.2 METHODS

Since reinjection may not always be required (such as at Wairakei in New Zealand and Cerro Prieto in Mexico), costs for production and reinjection surface facilities are considered separately. As for power plants described in Section 2, the cost data are adjusted to September 1984 price levels and are correlated with capacities using a power-law equation fitted by the log-log least squares method.

Table 4-1 lists the scope and exclusions for the cost estimates of geothermal wellfield surface facilities addressed in Section 4.

### 4.3 RESULTS

#### 4.3.1 Steam Resources

Figure 4-1 shows cost estimates for wellfield production surface facilities for The Geysers. The system for plant numbered 9 is controlled by manually adjusting valves at each wellhead, while the other three have automatic control facilities. Furthermore, the distances from the wellheads to the power plant are significantly shorter than is typical for the others. Both these differences in scope point toward lower capital cost for plant numbered 9; therefore, its cost is not used to define the power-law equation.

The power-law correlation in Figure 4-1 applies for probable and high cost systems. For low cost systems, a power-plant equation with the same exponent (slope on the log-log plot) is fitted through the cost estimate for plant numbered 9 to reflect the different scope, yet retain the same economy-of-scale characteristic. This changes the coefficient to 0.465 for low cost systems.

Figure 4-2 shows the cost estimates and power-law correlation for wellfield reinjection surface facilities for The Geysers.

#### 4.3.2 Hot Water Resources

New cost estimates were developed for the wellfield surface facilities. These new estimates were required because the data available from the geothermal literature and previous design studies were not adequate to develop cost correlations as was done for the power plants.

Table 4-1

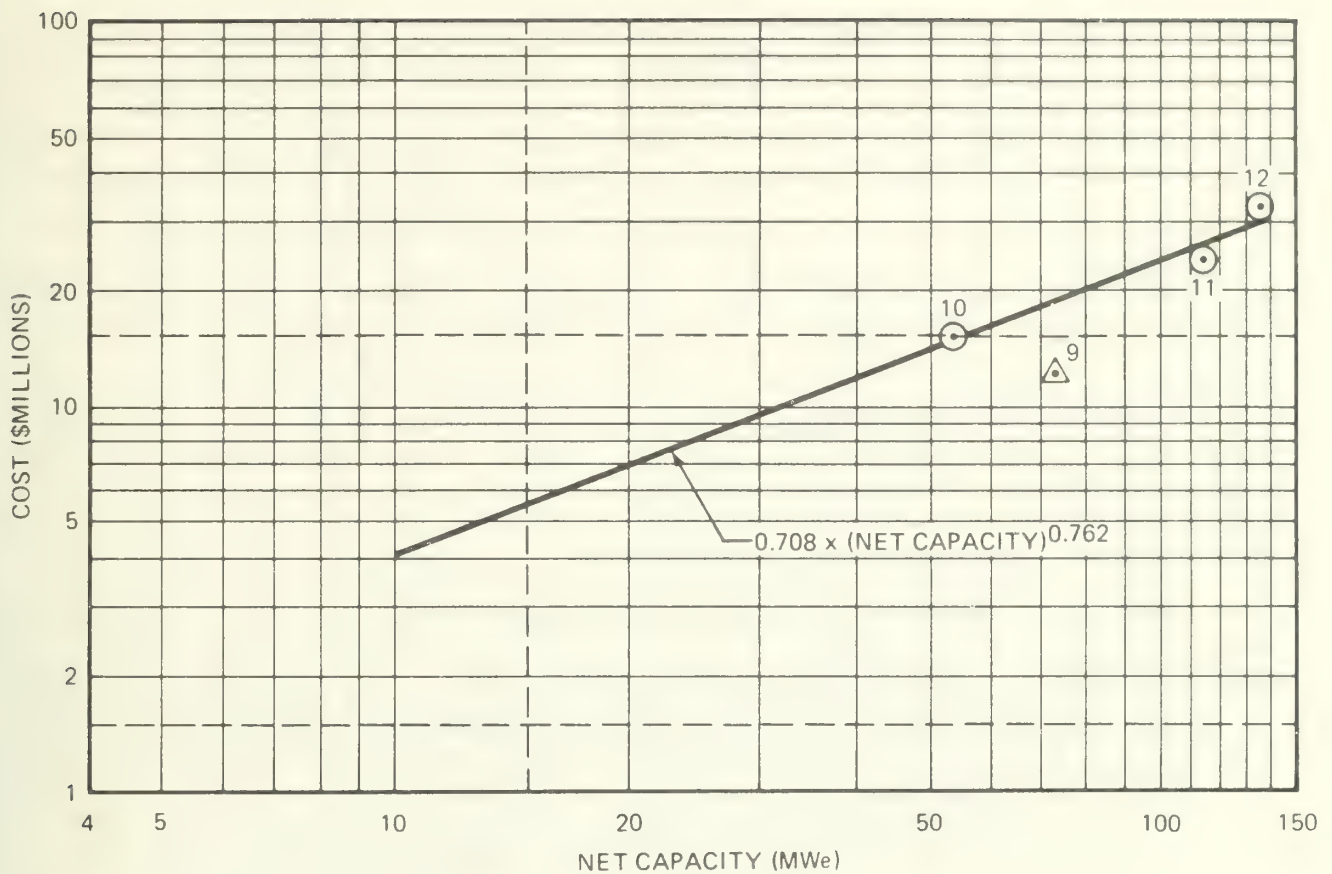
SCOPE AND EXCLUSIONS FOR COST ESTIMATES OF WELLFIELD SURFACE FACILITIES

Scope Included

Downhole pumps for production wells (binary only)  
Production wellpad piping and equipment downstream from wellhead shutoff valves  
Production wellpad particle and moisture separators (steam resources only)  
Production wellpad instrumentation and controls  
Steam or hot water transmission pipelines  
Condensate collection and disposal facilities (steam resources only)  
Flash tanks (flashed steam plants only)  
Steam release facility  
Startup system for production wells (flashed steam plants only)  
Reinjection pumps  
Reinjection pipeline  
Reinjection piping and equipment  
Reinjection instrumentation and controls  
Wellfield electrical system  
Wellfield control building  
Wellfield distributed digital automatic control system  
Construction labor  
Engineering, procurement, and construction management  
Indirect field costs  
Production and reinjection island development (clearing, grubbing, grading, etc.)  
On-site roads

Exclusions

Land and land use costs  
Interest during construction  
Inflation after September 1984  
Owner's engineering, administrative, and general costs  
Research and development costs  
Permits and licenses  
Production and reinjection wells  
Resource exploration  
Lease acquisition costs



**Figure 4-1 CAPITAL COST OF WELLFIELD PRODUCTION  
SURFACE FACILITIES, STEAM RESOURCE**

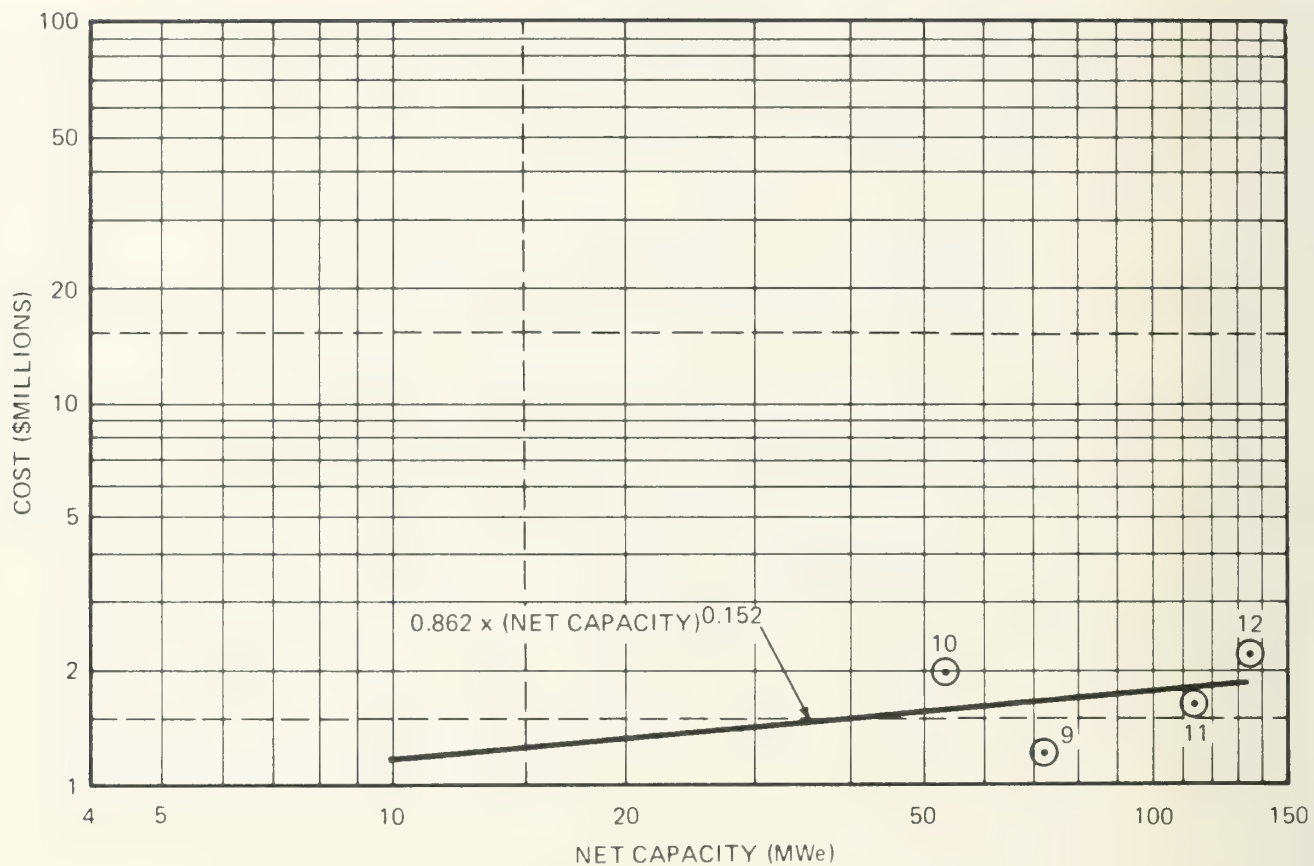


Figure 4-2 CAPITAL COST OF WELLFIELD REINJECTION  
SURFACE FACILITIES, STEAM RESOURCE

A conceptual design level cost estimate of a wellfield for a 350°F resource with a double flash plant (plant numbered 26) was used as an estimate for the basic wellfield facilities. The concept forming the basis of this estimate uses a single production well island near the power plant and a single reinjection well island about a mile away. For each case under consideration, the cost of the production and reinjection facilities was obtained by scaling the existing estimate according to the required flow rate and adding the estimated cost of the required transmission piping and, where appropriate, the estimated cost of flash vessels.

For each resource temperature, the low, probable, and high cost production facilities are defined as follows:

- o Low cost. All production wells are located on one production island near the power plant. The wells are directionally drilled.
- o Probable cost. The production wells are located on production islands with up to six wells per production island. The wells are directionally drilled.
- o High cost. The production wells are uniformly distributed over the production field. The wells are drilled vertically.

The low, probable, and high cost reinjection facilities are defined as follows:

- o Low cost. ReInjection is not required. The cost of disposal facilities for geothermal liquids is assumed to be insignificant.
- o Probable cost. All reinjection wells are located on one reinjection island one mile from the power plant. The wells are directionally drilled.
- o High cost. The reinjection wells are uniformly distributed over the reinjection field. The center of the reinjection field is one mile from the power plant. The wells are drilled vertically.

Additional assumptions that were used in developing the wellfield concepts are given in Table 4-2.

For each resource temperature, plant type, and relative cost system, cost estimates were developed for wellfields to support 10, 50 and 100 MWe (net) power plants.

Figures 4-3 through 4-14 show the production and reinjection cost estimates and power-law correlations for hot water resources as follows:

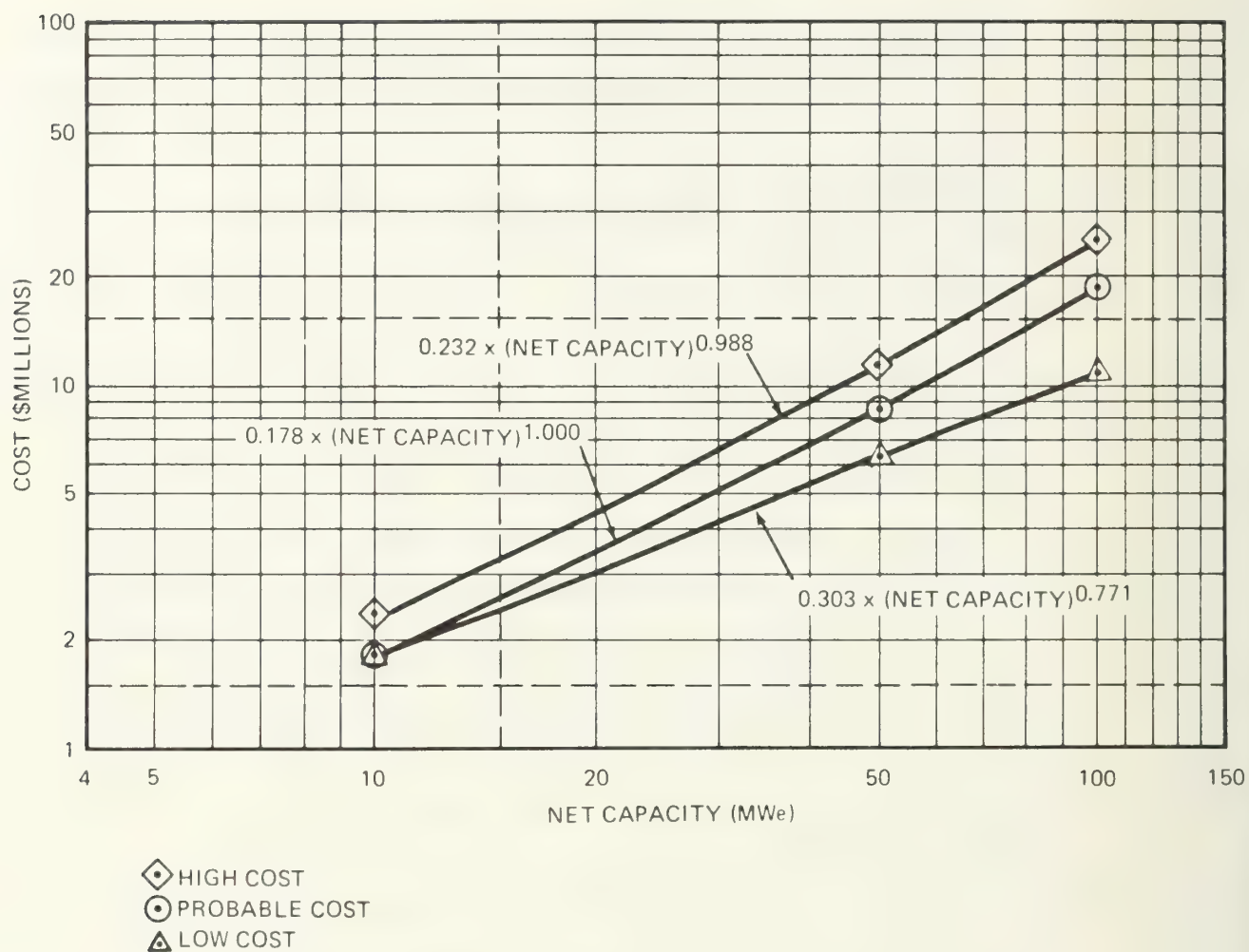
- o 530°F, Single flash - Figures 4-3 and 4-4
- o 530°F, Double flash - Figures 4-5 and 4-6
- o 420°F, Single flash - Figures 4-7 and 4-8
- o 420°F, Double flash - Figures 4-9 and 4-10
- o 350°F, Double flash - Figures 4-11 and 4-12
- o 350°F, Binary - Figures 4-13 and 4-14

In all cases, the power-law correlation equations fit the plotted points within ±5 percent.

Table 4-2

ASSUMPTIONS FOR DEVELOPING WELLFIELD CONCEPTS  
FOR HOT WATER RESOURCES

- o For a given resource temperature and plant type, flow rate is proportional to plant capacity
- o Costs for all items except piping are scaled according to the 0.7 power of flow rate
- o All piping is Schedule 40
- o Production piping has 2.5 inches of fiberglass insulation, and reinjection piping has 1 inch
- o The resource supports 50 MWe per square mile
- o Each well supports 5 MWe (net) of power generation
- o There are no terrain restrictions on pipe routing
- o The production wellfield is rectangular, and the power plant is in the center of the field
- o The reinjection wells have the same spacing as the production wells
- o One reinjection well is needed for two production wells
- o The reinjection field is rectangular, with its center located one mile from the power plant



**Figure 4-3 CAPITAL COST OF WELLFIELD PRODUCTION  
SURFACE FACILITIES, 530°F HOT WATER  
RESOURCE, SINGLE FLASH**

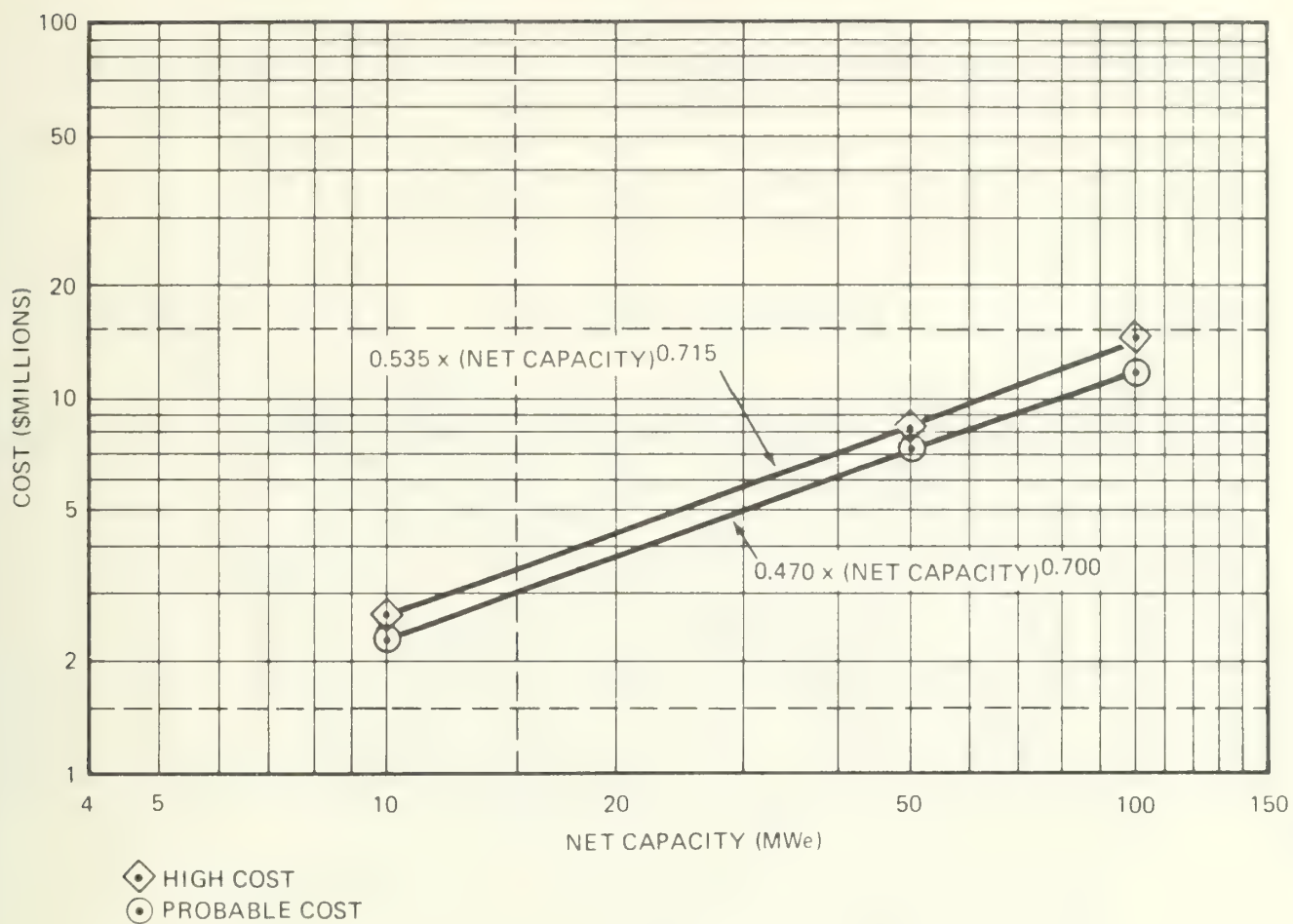


Figure 4-4 CAPITAL COST OF WELLFIELD REINJECTION  
SURFACE FACILITIES, 530°F HOT WATER  
RESOURCE, SINGLE FLASH

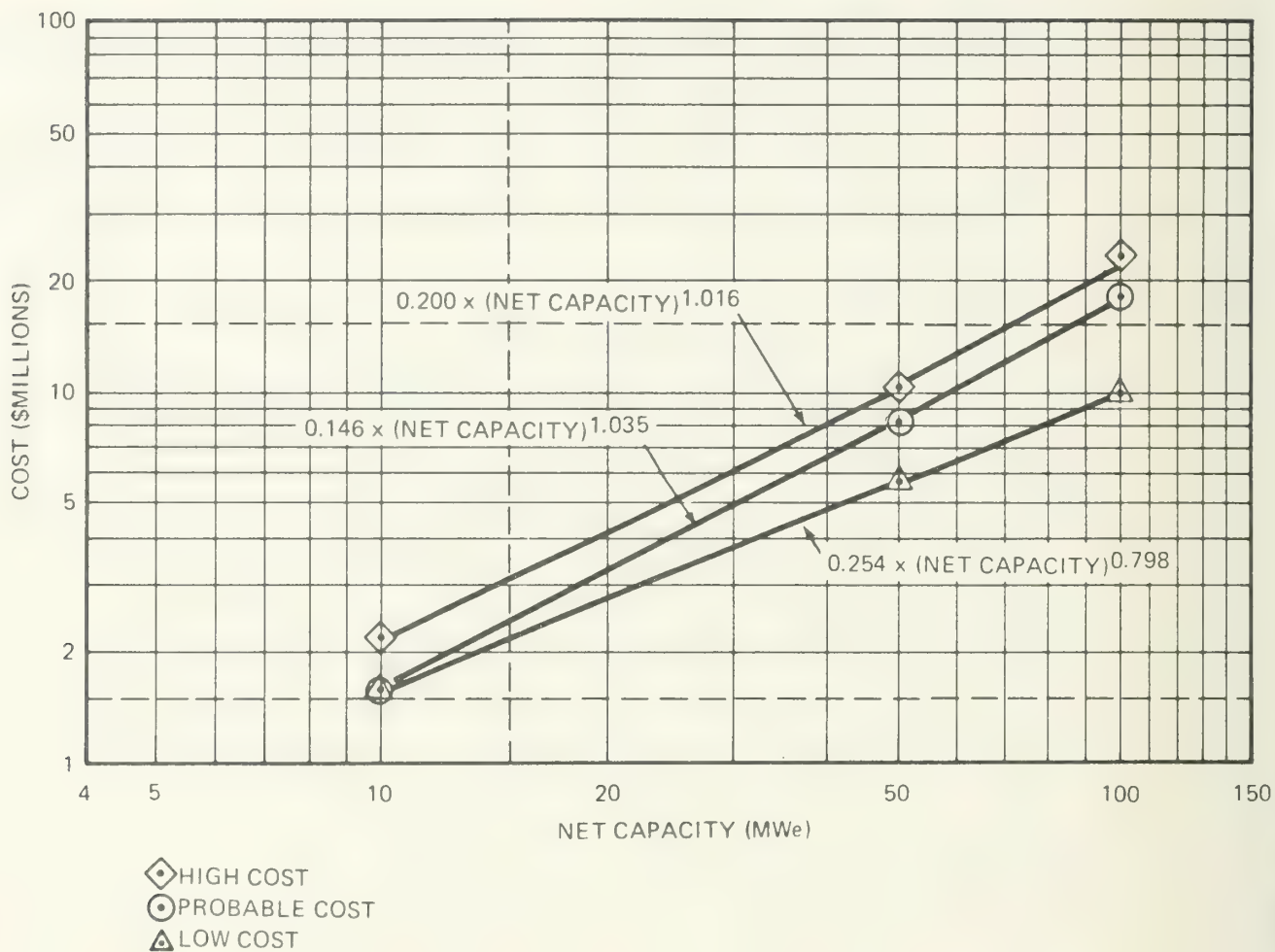
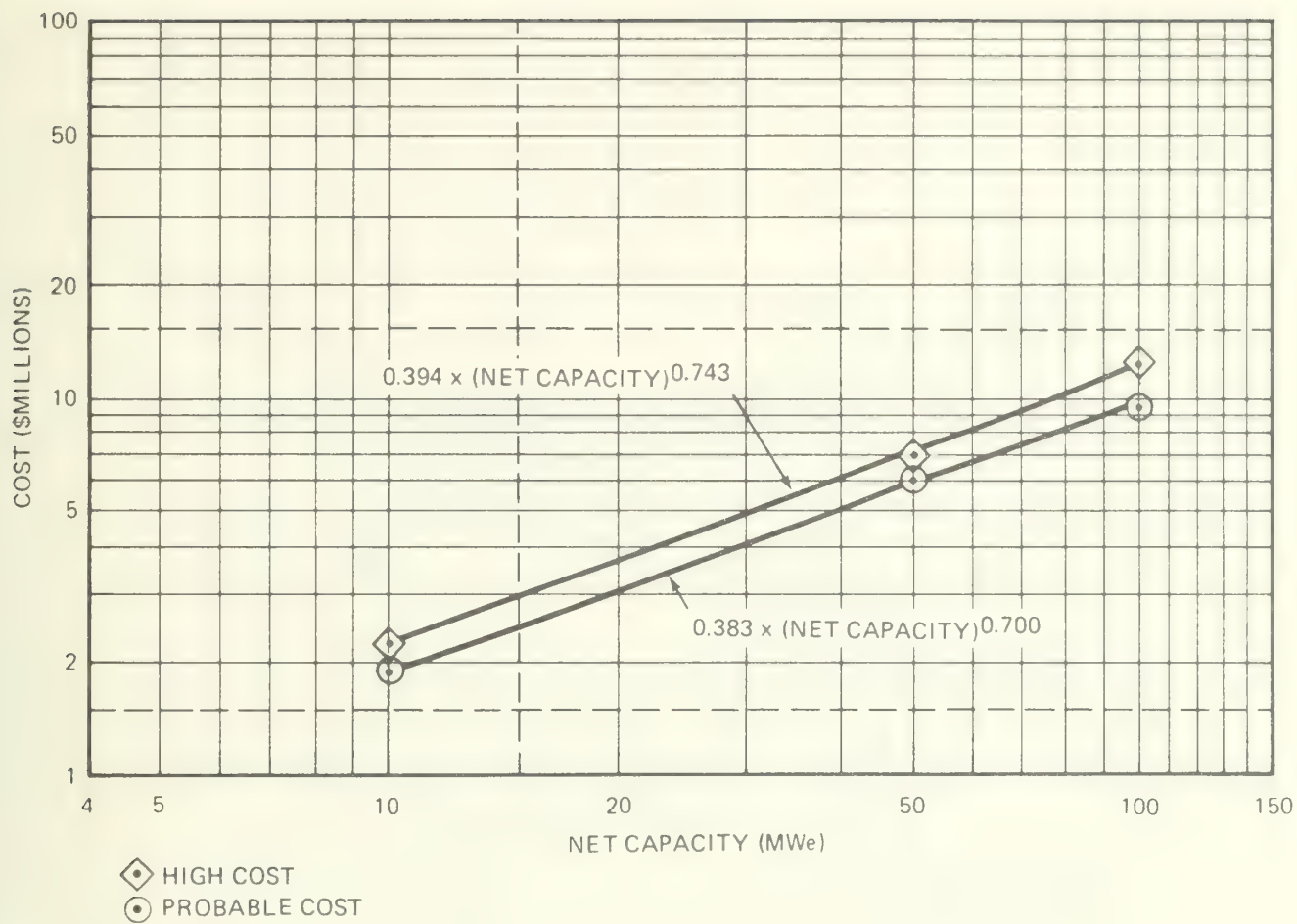


Figure 4-5 CAPITAL COST OF WELLFIELD PRODUCTION  
SURFACE FACILITIES, 530°F HOT WATER  
RESOURCE, DOUBLE FLASH



**Figure 4-6 CAPITAL COST OF WELLFIELD REINJECTION  
SURFACE FACILITIES, 530°F HOT WATER  
RESOURCE, DOUBLE FLASH**

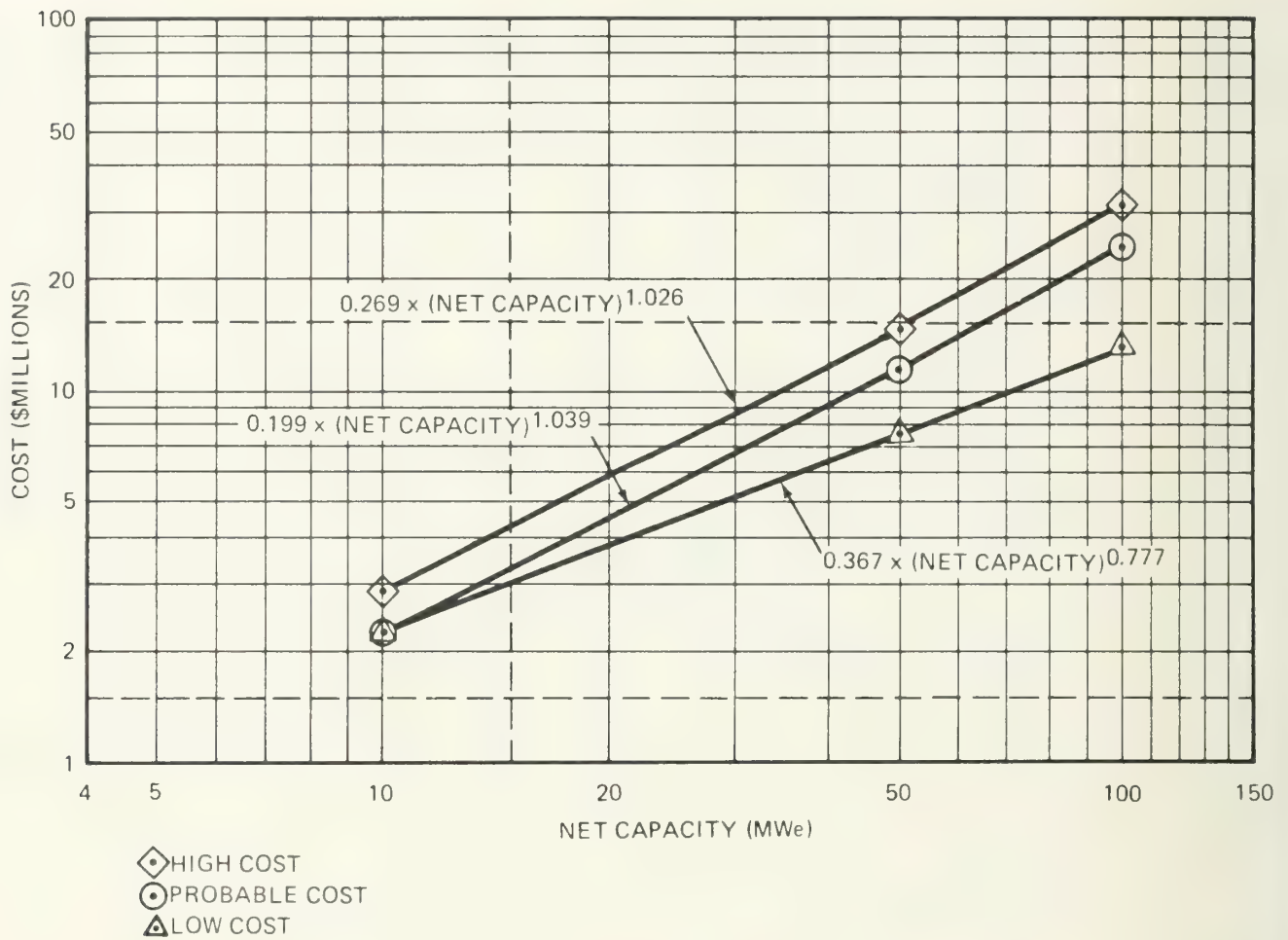


Figure 4-7 CAPITAL COST OF WELLFIELD PRODUCTION  
SURFACE FACILITIES, 420°F HOT WATER  
RESOURCE, SINGLE FLASH

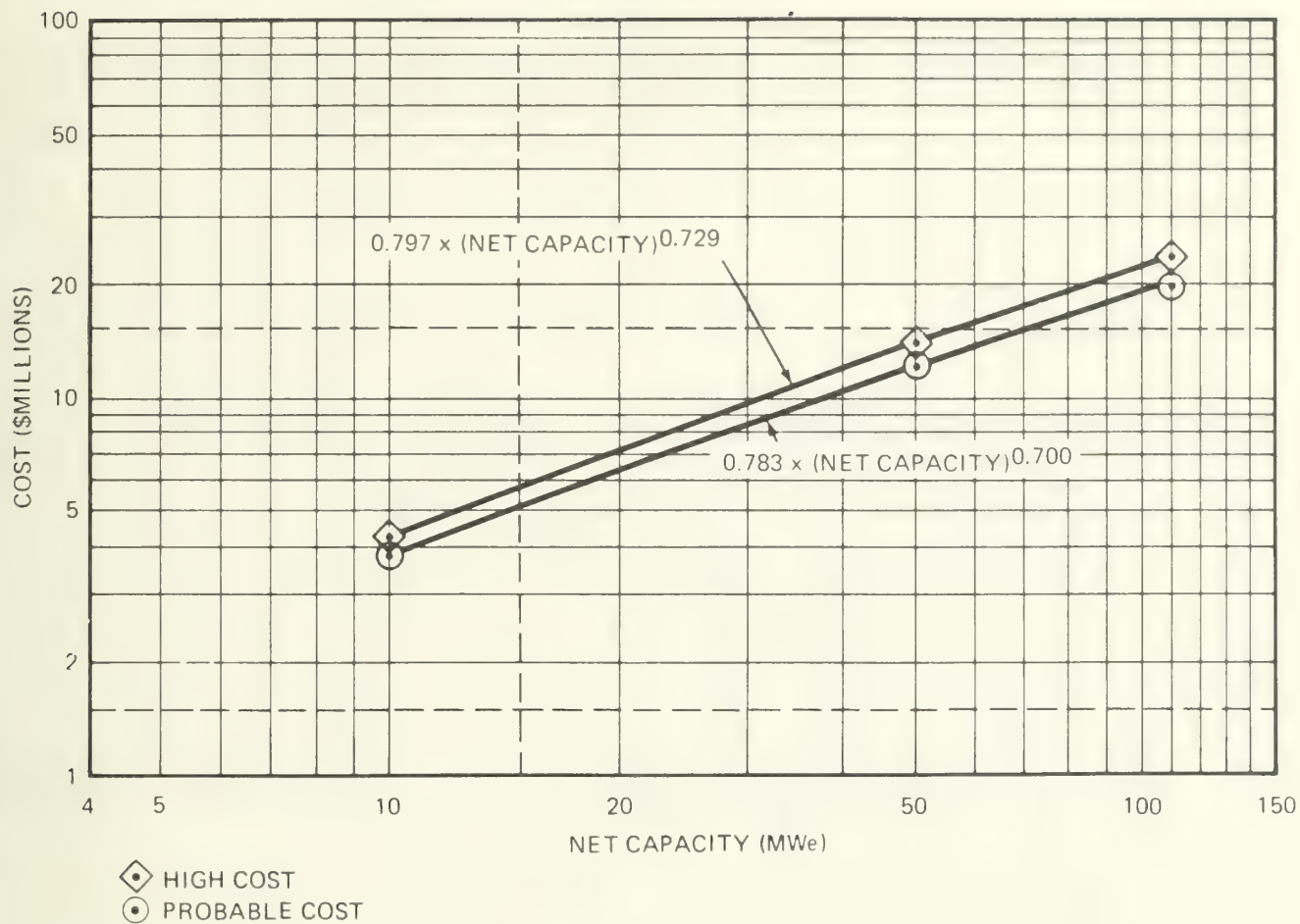


Figure 4-8 CAPITAL COST OF WELLFIELD REINJECTION  
SURFACE FACILITIES, 420°F HOT WATER  
RESOURCE, SINGLE FLASH

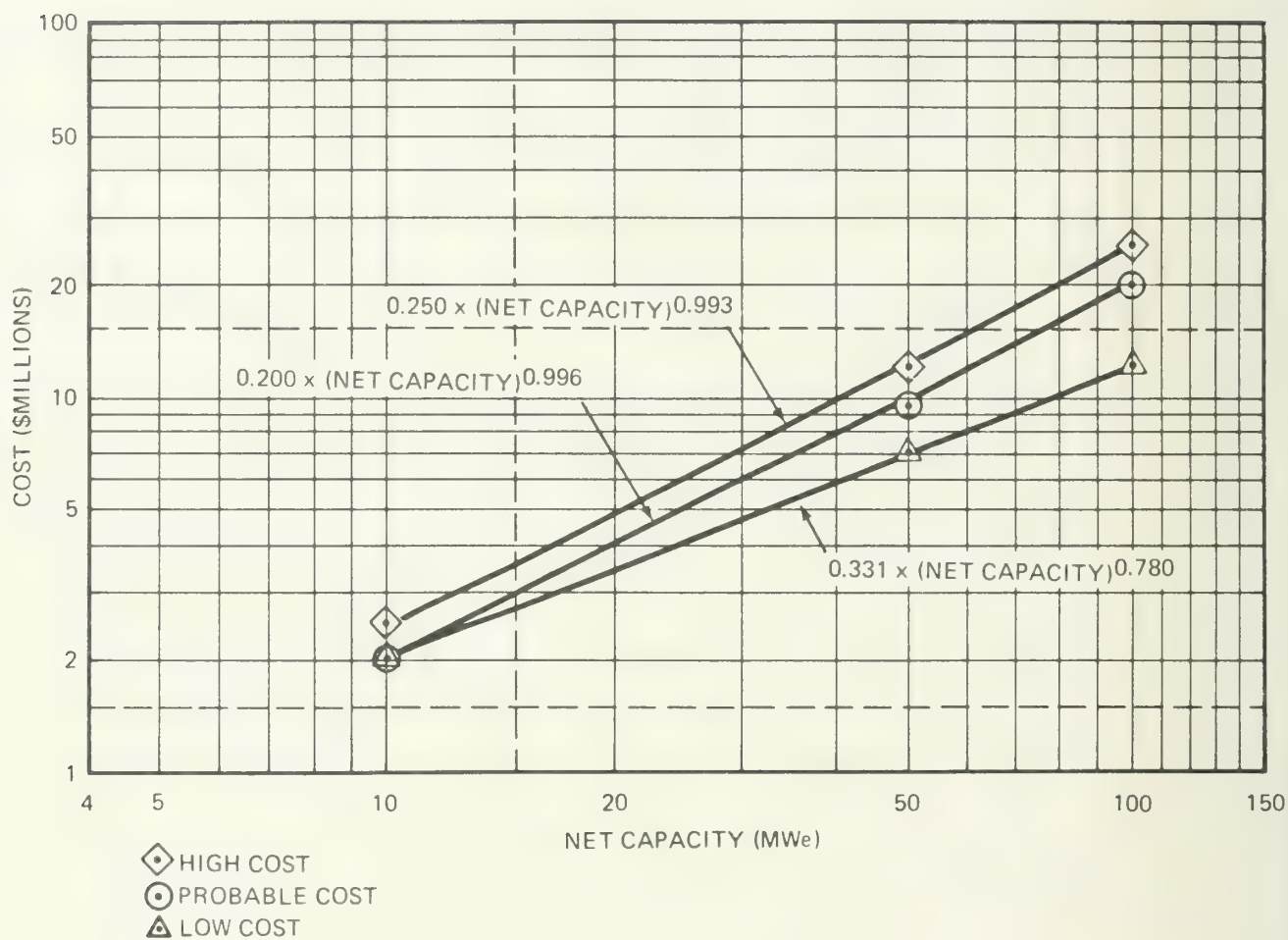
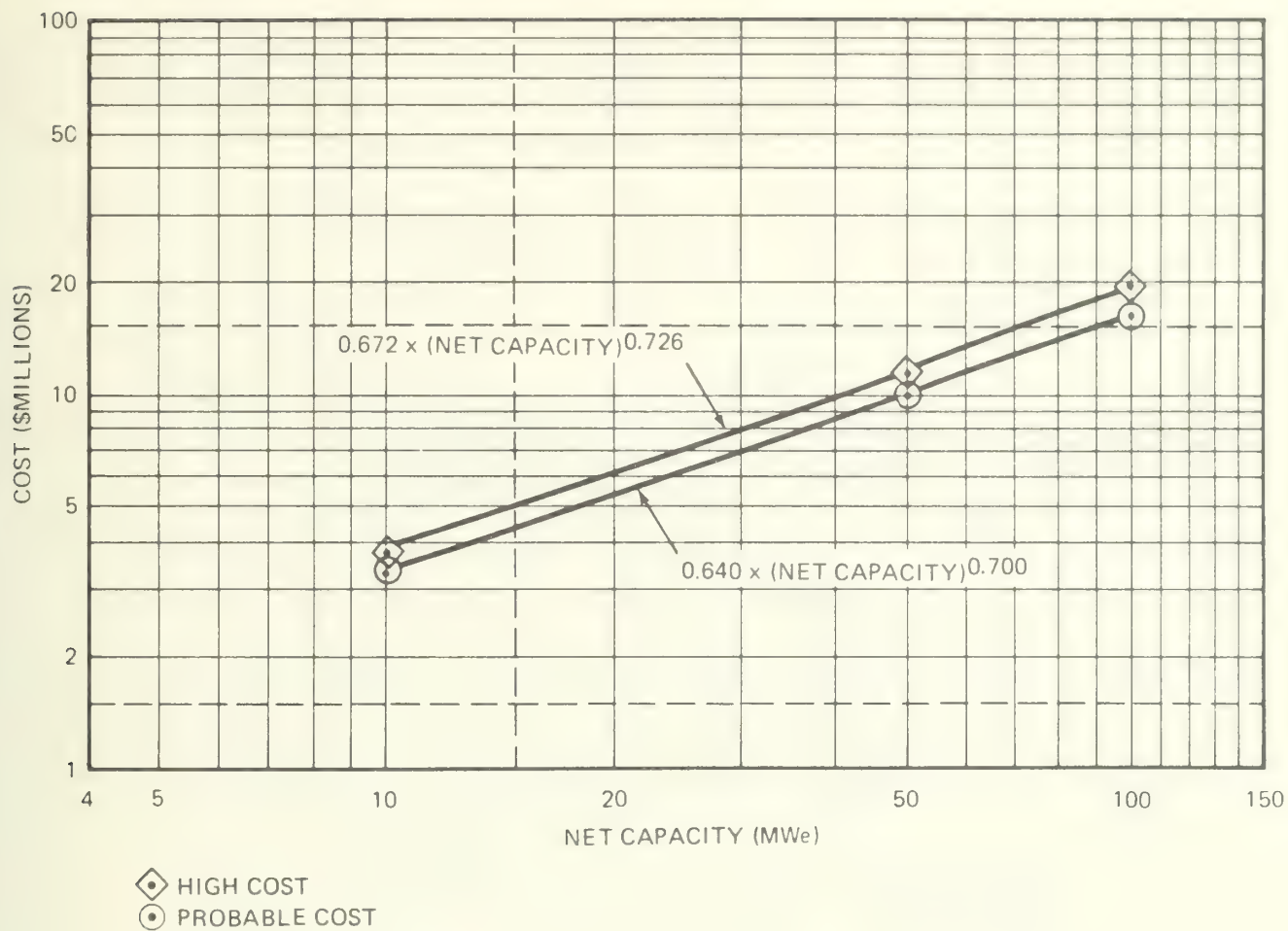
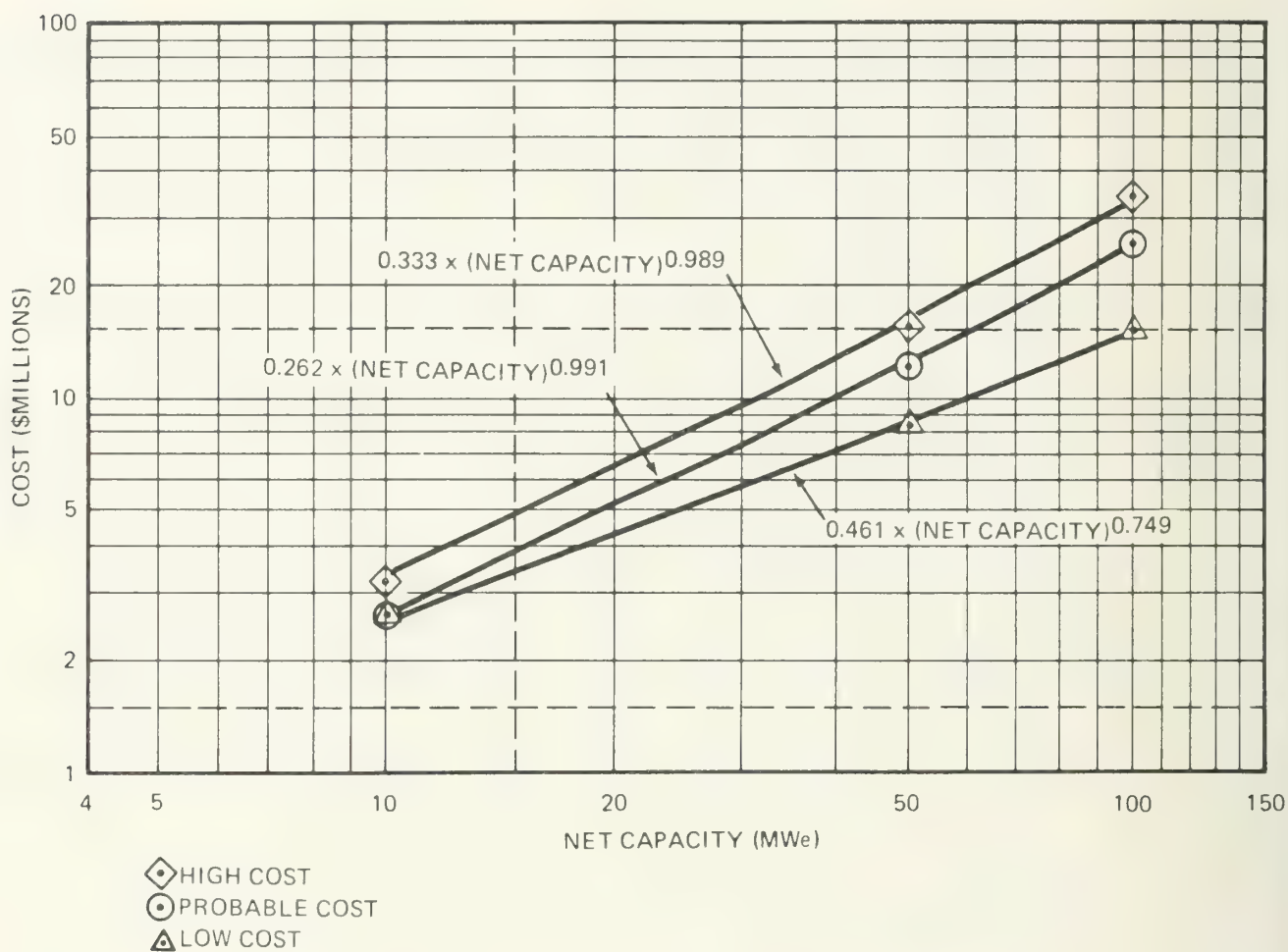


Figure 4-9 CAPITAL COST OF WELLFIELD PRODUCTION  
SURFACE FACILITIES, 420°F HOT WATER  
RESOURCE, DOUBLE FLASH



**Figure 4-10 CAPITAL COST OF WELLFIELD REINJECTION  
SURFACE FACILITIES, 420°F HOT WATER  
RESOURCE, DOUBLE FLASH**



**Figure 4-11 CAPITAL COST OF WELLFIELD PRODUCTION  
SURFACE FACILITIES, 350°F HOT WATER  
RESOURCE, DOUBLE FLASH**

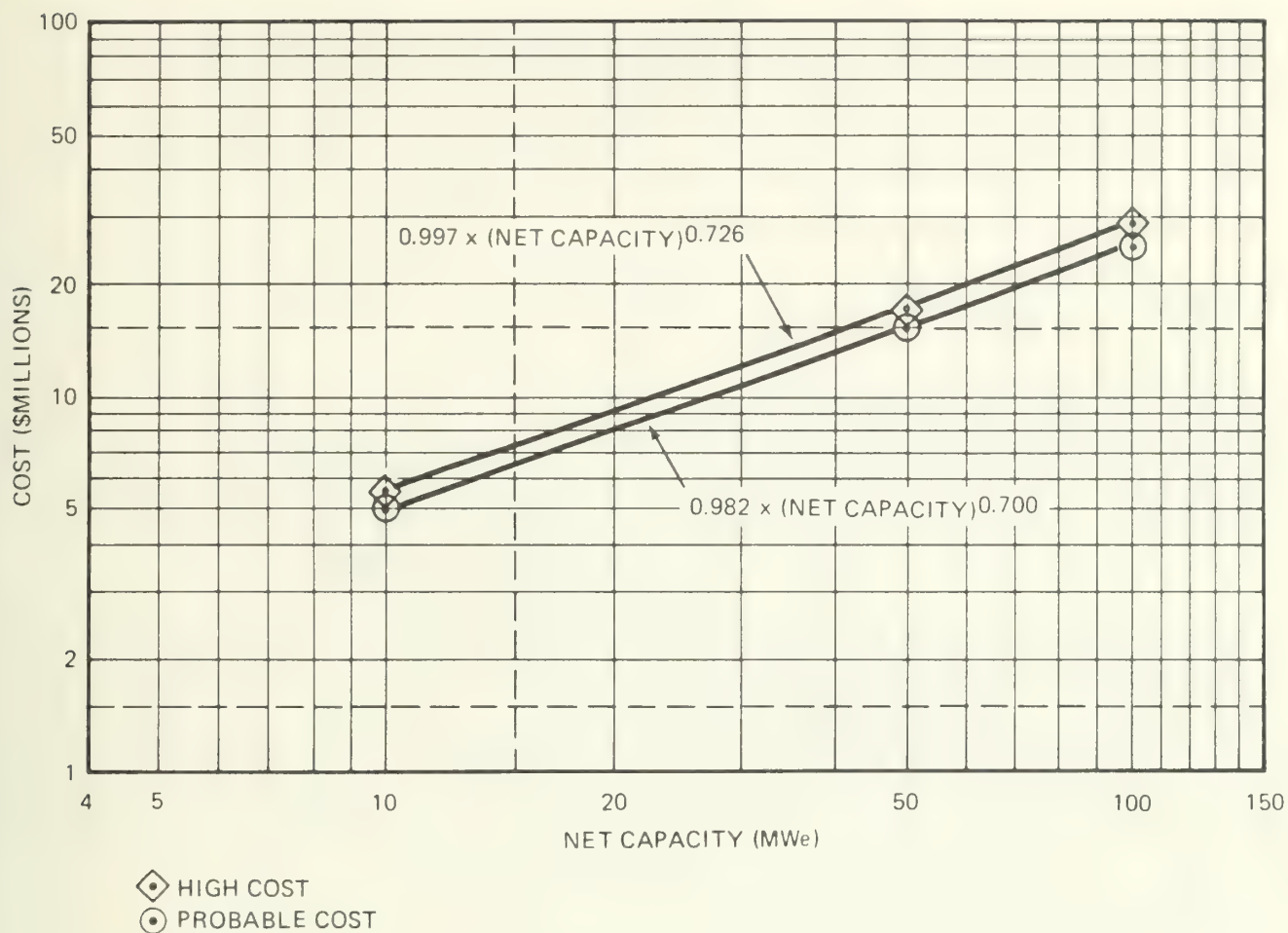


Figure 4-12 CAPITAL COST OF WELLFIELD REINJECTION  
SURFACE FACILITIES, 350°F HOT WATER  
RESOURCE, DOUBLE FLASH

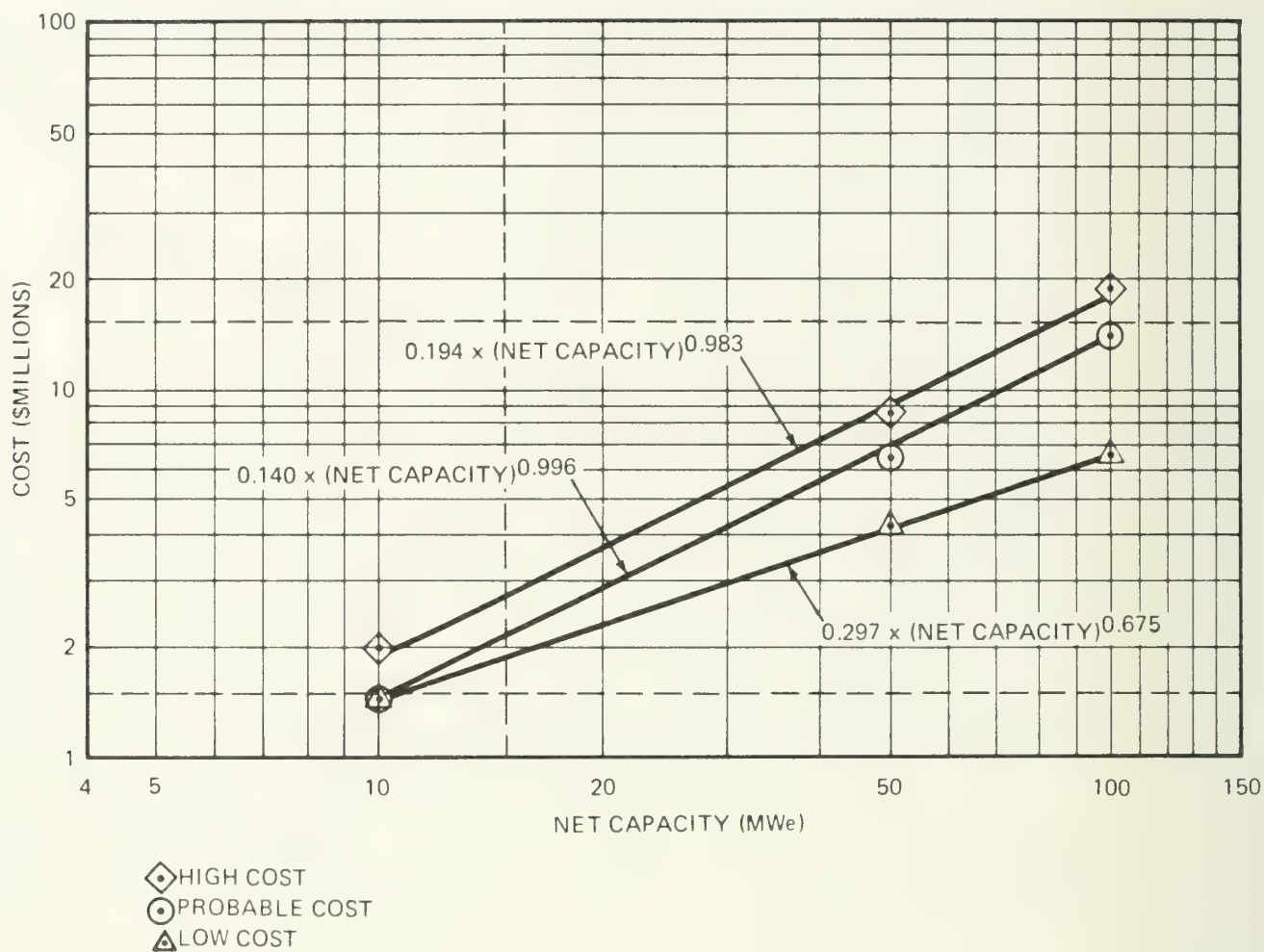


Figure 4-13 CAPITAL COST OF WELLFIELD PRODUCTION  
SURFACE FACILITIES, 350°F HOT WATER  
RESOURCE, BINARY

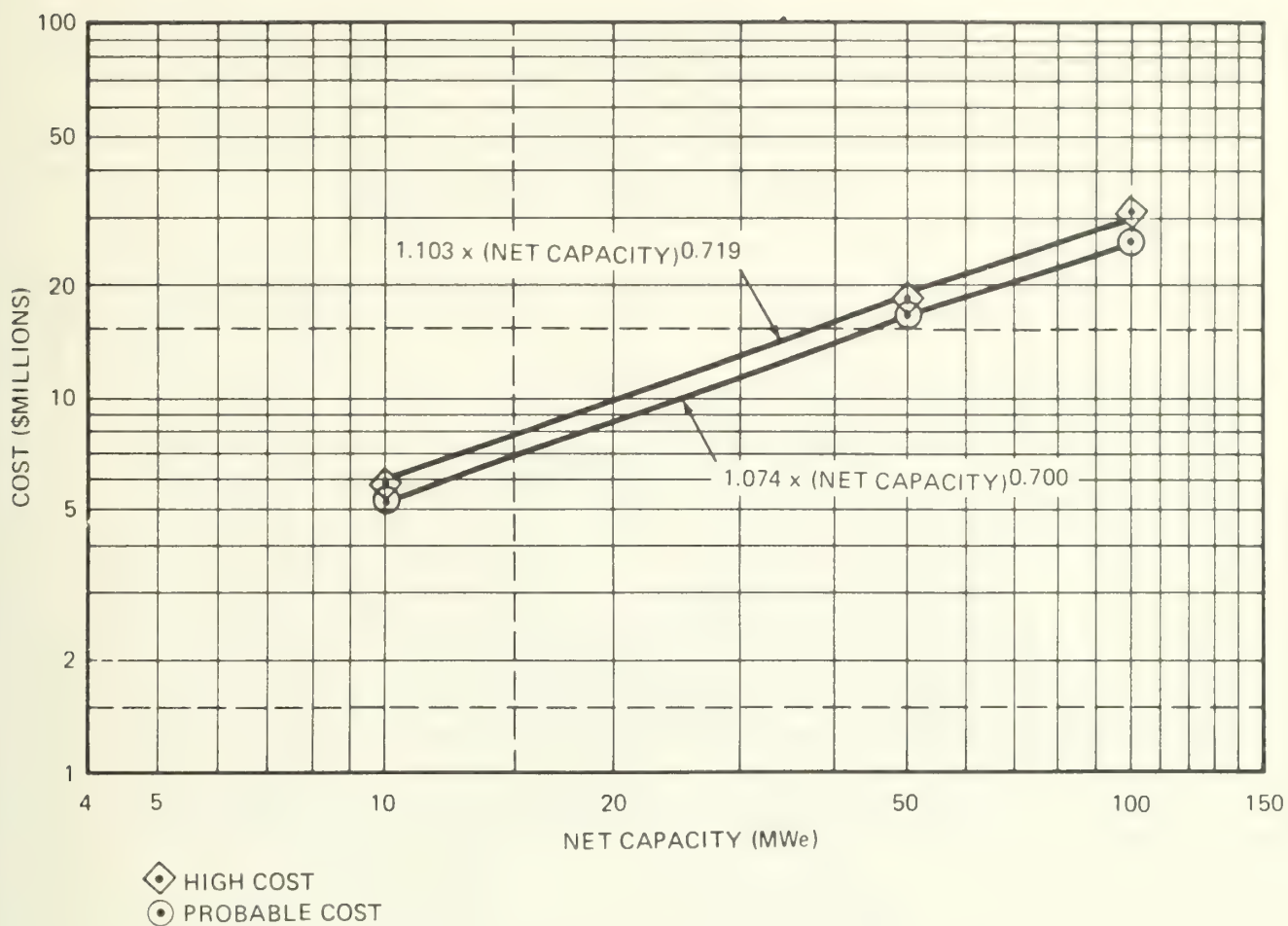


Figure 4-14 CAPITAL COST OF WELLFIELD REINJECTION SURFACE FACILITIES, 350°F HOT WATER RESOURCE, BINARY



## Section 5

### OPERATING AND MAINTENANCE COSTS FOR WELLFIELD SURFACE FACILITIES

The annual O&M costs for geothermal wellfield surface facilities consist of the following:

- o Operating labor includes the wages and labor burden for the operators and technicians who monitor the wellfield operation and make the adjustments and minor repairs needed to provide geothermal fluid to the power plant under varying load and process conditions.
- o Maintenance costs are for the labor and materials needed to maintain the wellfield surface facilities. Maintenance costs for the wells are not included in this report. They must be derived from other sources and added to arrive at total wellfield O&M costs.
- o Overhead charges are for administrative and support labor directly connected with the wellfield operation and maintenance.
- o Pumping costs are for the electric energy needed to operate the reinjection pumps. For binary plants, the pumping costs also include the electric energy needed for the production pumps.

An estimate of the annual O&M costs for the wellfield surface facilities was prepared using a procedure outlined by EPRI (Ref. 1-1). Although this procedure is not specific to geothermal wellfields, adaptation of this approach is expected to yield a realistic result that can be used in economic screening.

#### 5.1 OPERATING LABOR

The number and type of personnel needed to operate a geothermal wellfield are independent of electric generating capacity for installations in the 10 to 100 MWe range. Operations at The Geysers show that one wellfield operating crew can operate multiple wellfields if remote manual or

automatic control equipment is installed. Aminoil is currently operating the wellfields for PG&E Unit 13, monitoring SMUDGE #1, and plans to operate future PG&E Units 16 and 19 from one control building with one crew of operating personnel. This will result in lower operating labor cost per kWh of electric energy. The reasonable maximum number of wellfields operable by one crew appears to be about six wellfields for steam and binary plants and about four wellfields for flashed steam plants where the geothermal fluid has relatively low dissolved solids.

For this report, an operating crew appropriate for a wellfield serving a power plant in the 10 to 100 MWe range is defined, and the annual cost for employing the personnel is estimated.

The wellfield operating crew is assumed to consist of four chief operators (one for each weekly shift), five operators, two electro/mechanical technicians, and one reservoir engineer.

For wellfield operations, the wage rate for operators and technicians is estimated as \$15 per hour. This is the same wage rate that is used for power plant operators (see Subsection 3.1). Chief operators are assumed to earn an average of 20 percent more than operators, and the reservoir engineer is assumed to earn 50 percent more. Labor additives for FICA, holidays, sick leave, etc. are taken as 35 percent of wages and salaries. The total annual operating labor cost for a typical wellfield equals \$560,000 by the above estimating procedure.

## 5.2 MAINTENANCE

The EPRI procedure previously mentioned is used for estimating annual maintenance costs for wellfield surface facilities as a percent of capital cost. Appropriate percentage values are taken from Table 3-1. Since corrosion is likely to be more severe for the wellfield surface facilities than for the power plant, the percentage values are higher. For steam resources, the percentage value is expected to be about 4 percent for low and probable severity service and 6 percent for high severity service. For hot water resources, it is expected to be

6 percent for low and probable severity service and 8 percent for high severity service.

### 5.3 OVERHEAD CHARGES

The overhead charges for administrative and support labor are assumed to equal 30 percent of the costs for operating and maintenance labor as recommended by EPRI (Ref. 1-1). Maintenance labor is assumed to account for 40 percent of the annual maintenance costs.

### 5.4 PUMPING COST

The pumping cost for reinjection is estimated by assuming that the differential pressure across the pumps is 250 psi for the probable cost reinjection and 500 psi for high cost reinjection.

Experience at The Geysers indicates that reinjection pumping is not needed with a steam resource, and the water flows into the reinjection wells under gravity head.

For a binary plant, pumping is required using a downhole pump in each production well. To estimate this pumping cost, a pump differential pressure of 250 psi was assumed for low and probable cost production, and 500 psi was assumed for high cost operation. This production pumping cost is added to the reinjection pumping cost for binary plants.

To determine the annual pumping cost, the annual energy consumption is calculated from the differential pressure, flow rate (expressed as a linear function of capacity), and annual power plant capacity factor. This annual energy consumption is then multiplied by the average electric energy cost to determine the annual pumping cost. This calculation is simplified by combining differential pressure, flow per MWe capacity, and a number of constants into one "pumping power factor" for each type of plant. A term for calculating the annual pumping cost and a table of the pumping power factor are given in Section 7.4.

## 5.5 WELLFIELD O&M COSTS

The overhead charges can be incorporated into the terms for operating labor and maintenance costs, as discussed in Subsection 3.4 for power plant O&M costs. This results in the following equation for wellfield O&M costs:

$$\begin{aligned}\text{Annual O\&M costs} &= 1.3 \times \text{operating labor cost} \\ &\quad + 1.12 \times \text{maintenance cost} \\ &\quad + \text{pumping cost}\end{aligned}$$

Specific details for estimating the wellfield O&M costs are given in Section 7.4.

## Section 6

### ADJUSTMENTS

Construction cost adjustments for mountainous terrain, inadequate local construction labor, and interest during construction are discussed below.

#### 6.1 MOUNTAINOUS TERRAIN

The following two aspects of constructing a geothermal power project in mountainous terrain are the most likely to cause increased capital costs:

- o Site Preparation. If site preparation involves moving large quantities of soil and rock, the costs would be increased compared to construction on relatively level land.
- o Loss of Labor Productivity. In the mountainous region of The Geysers, construction workers are bused to each construction site due to limited road access, and the time spent in transit is charged to the construction payroll. This loss of labor productivity increases construction costs.

The cost-increasing effects of these two characteristics of mountainous terrain are quantified below.

##### 6.1.1 Site Preparation

Site preparation work involves the clearing, grubbing, grading, filling, and leveling needed to prepare a plot of 3 to 10 acres needed for a geothermal power generating facility. For level or gently sloping land, this involves clearing, grubbing, and minimal grading. In mountainous terrain, a level pad of the necessary size is often created by extensive cutting and filling. In some cases, the leveled area is about half cutaway hillside and half fill. At The Geysers, the rock can usually be ripped for this earth moving, but extensive blasting is often also required. With so many variables, the site preparation cost is quite different from site to site. However, a generic adjustment is possible because site preparation cost usually amounts to only a few percentage

points of the total construction cost; therefore, large variations in cost of site preparation do not cause very large changes in total cost.

To quantify this effect, data from the following three cost estimates were used:

- o Plant numbered 2. The cost estimate for site preparation is 2.1 percent of total plant cost.
- o Plant numbered 3. The estimate for site work is 0.8 percent of the total, but it specifically excludes earth moving costs.
- o Plant numbered 6. The cost estimate for site preparation is 3.3 percent of total plant cost.

Thus, earth moving costs for plants numbered 2 and 6 are on the order of 1.3 and 2.5 percent, respectively. An average of about 2 percent of total plant cost could be expected to represent a generic increase in site preparation cost compared to construction on flat land. To adjust for site preparation costs in mountainous terrain, the power plant cost from Section 2 should be multiplied by the factor 1.02.

Site preparation costs may vary significantly from one site to another. Therefore, the adjustment suggested here may not account very accurately for the site preparation costs for a particular site. However, it does point out that a typical adjustment is relatively small - only a few percentage points of total plant cost.

For wellfield surface facilities, an adjustment for added site preparation costs in mountainous terrain is probably about the same low percentage of total cost.

#### 6.1.2 Loss of Labor Productivity

Due to limited road access to most construction sites at The Geysers, a construction worker is typically paid for eight hours per day, but paid travel time on a company furnished bus usually amounts to about one hour

daily. Therefore, installation labor costs in areas where this situation does not exist should be multiplied by 8/7 to adjust for this loss of productivity.

Installation labor for geothermal power plants usually accounts for 15 to 20 percent of the total cost. Therefore, the total plant cost should be multiplied by 1.02 to 1.03 to adjust for this loss of labor productivity.

The cost of wellfield surface facilities probably should be adjusted about the same percentage for a similar loss of labor productivity.

## 6.2 INADEQUATE LOCAL CONSTRUCTION LABOR

Some remote areas where geothermal power projects may be located are beyond a feasible commuting distance from an adequate pool of construction labor. In situations like this, a construction camp would be established and operated to provide living quarters and meals for the workers.

Costs for a construction camp were estimated for plant numbered 19, and these data were adjusted for inflation and applied to estimate the added costs for establishing and operating a construction camp. Maximum and average crew sizes were estimated as functions of plant capacity, and the duration of the construction period was taken from the correlation shown in Figure 6-1. The expression for construction camp costs (in millions of dollars at September 1984 price levels) is as follows:

$$\text{Construction Camp Cost} = A \times (\text{Net Capacity})^{0.5} + B \times (\text{Net Capacity})^{0.78}$$

Where A = 0.266 for the power plant and  
0.109 for the wellfield surface  
facilities, and

B = 0.110 for the power plant and  
0.037 for the wellfield surface  
facilities

Since the power plant and the wellfield are usually owned by different organizations, the construction camp costs for the two should be

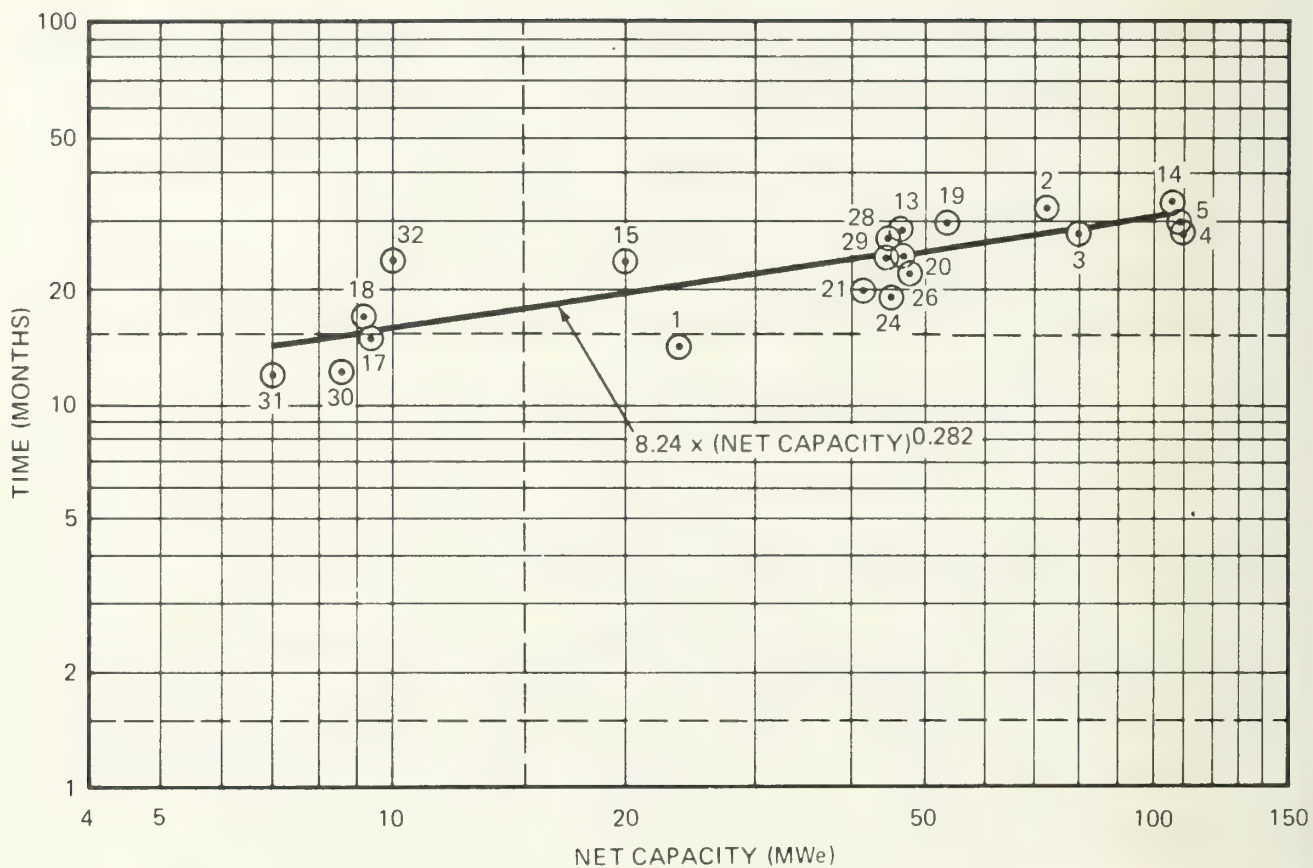


Figure 6-1 TIME REQUIRED FOR POWER PLANT CONSTRUCTION

calculated separately and added to their respective cost estimates. Actually, only one construction camp would probably be established to serve both groups; however, keeping the cost estimates separate allows independent calculation of costs for the wellfield owner and the power plant owner.

### 6.3 INTEREST DURING CONSTRUCTION

Interest during construction (IDC) for an interest rate,  $r$ , can be calculated by the following equation:

$$IDC = [(1 + r)^{TM} - 1] \times \text{Capital Costs}$$

where  $TM$  is the time (in years) from the centroid of expenditures to the date of commercial operation.

The time period,  $TM$ , is often approximated as one-third of the time from start of design to the date of commercial operation. This time to design and build (in months) is shown in Figure 6-2. Dividing the power-law equation from Figure 6-2 by 12 and multiplying by one-third, yields the following equation:

$$TM = 0.439 \times (\text{Net Capacity})^{0.208}$$

Using the same equation for  $TM$  for the wellfield is expected to yield a reasonable approximation for calculating wellfield IDC.

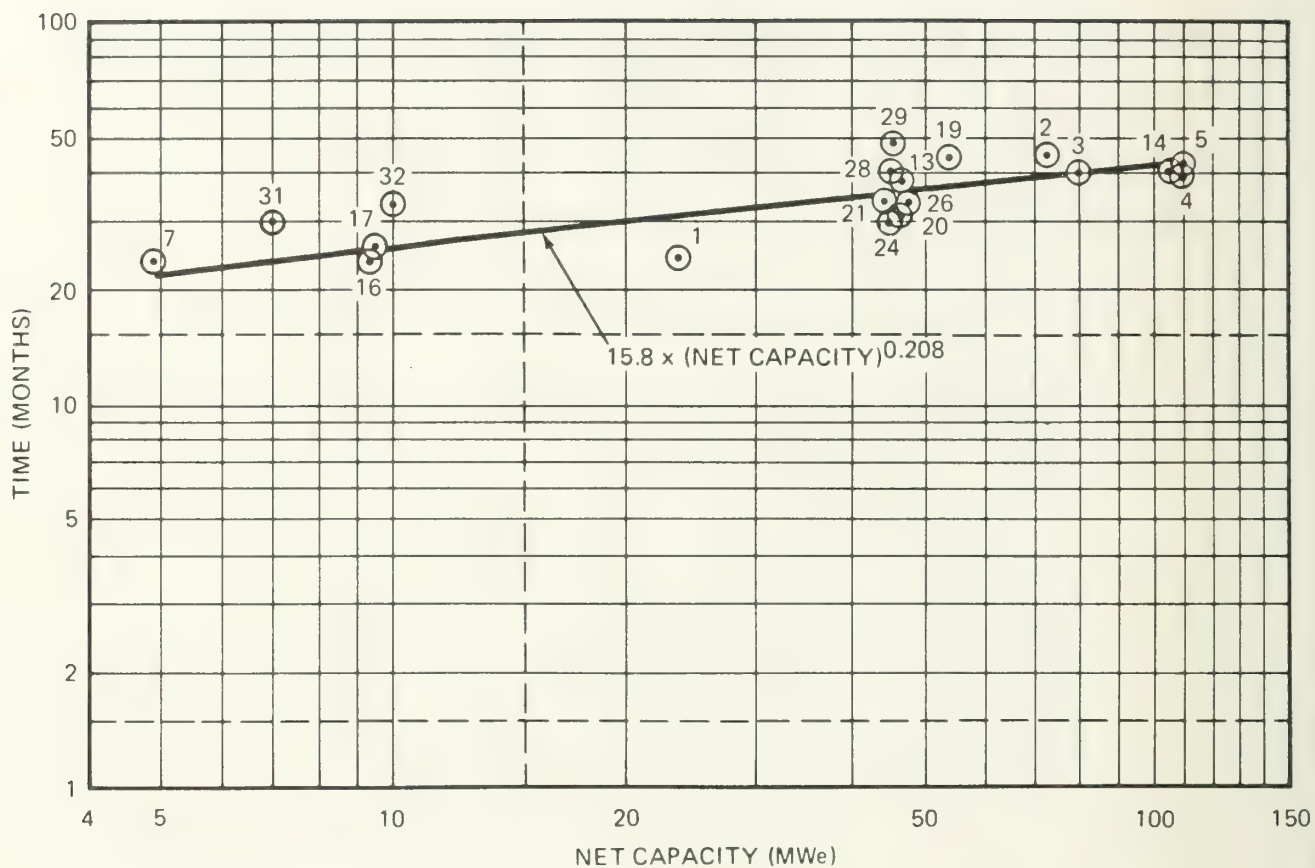


Figure 6-2 TIME FROM START OF DETAIL DESIGN  
TO COMMERCIAL OPERATION

## Section 7

### APPLICATION OF THE RESULTS

Previous sections of this report have presented cost data and correlations. This section summarizes the methods for applying the results to estimate the cost of a geothermal power generating facility. The steps described in the subsections below should be followed in the order given, and followed in their entirety to ensure that complete cost estimates are developed for use in the economic analysis. All costs are expressed as millions of dollars at September 1984 price levels, and net capacity is in MWe. Cost estimates for Biphase power modules and for Ormat binary units are presented separately in Sections 7.5 and 7.6 respectively.

#### 7.1 POWER PLANT CAPITAL COSTS

##### 7.1.1 Power Plant

Capital cost for a geothermal power plant can be estimated using a power law equation as follows:

$$\text{Cost} = a_1 \times (\text{Net Capacity})^{b_1}$$

The values for the coefficient,  $a_1$ , and the exponent,  $b_1$  are given in Table 7-1 for the various types of resources and power plants. This estimate is for a power plant without  $\text{H}_2\text{S}$  abatement equipment and located in flat, open terrain with adequate local construction labor.

##### 7.1.2 $\text{H}_2\text{S}$ Abatement

For situations where  $\text{H}_2\text{S}$  abatement is required, the capital cost of a Stretford system to control the  $\text{H}_2\text{S}$  can be approximated by the following equation:

$$\text{Cost} = 0.838 \times (\text{Net Capacity})^{0.426}$$

This term is added to the plant cost discussed in Section 7.1.1.

Table 7-1

## COEFFICIENTS AND EXPONENTS FOR POWER PLANT COST EQUATION

Resource Type	Resource Temperature (°F)	Power Plant Type	$a_1$	$b_1$
Steam	N/A	Direct steam	2.26	0.699
Hot water	530	Single flash	2.40	0.699
Hot water	530	Double flash	2.47	0.699
Hot water	420	Single flash	2.82	0.699
Hot water	420	Double flash	2.56	0.699
Hot water	350	Double flash	4.06	0.699
Hot water	350	Binary	2.09	1.015

Since a binary plant prevents the  $H_2S$  from separating from the geothermal liquid, the  $H_2S$  is disposed of along with the reinjected liquid. Therefore, an  $H_2S$  abatement system is not needed with a binary plant.

### 7.1.3 Adjustments

Terrain. The capital cost estimates in Sections 7.1.1 and 7.1.2 apply for relatively open terrain, like that in eastern Washington and Oregon, southern Idaho, and many of the river valleys in Montana. In these areas, construction sites would be accessible by road without undue traffic congestion or hazard, and earth moving for site preparation would be minimal.

For mountainous terrain, adjustments may be needed to account for loss of labor productivity and for additional site preparation costs as follows:

- o Loss of labor productivity. Multiply the sum from Sections 7.1.1 and 7.1.2 by the factor 1.02. (This adjustment should not be used if the cost of a construction camp is added for areas with inadequate local construction labor, as explained below.)
- o Additional site preparation. Multiply the sum from Sections 7.1.1 and 7.1.2 by the factor 1.02.

Inadequate Local Construction Labor. For situations that require the use of a construction camp to compensate for inadequate local construction labor, add the following to the sum from Sections 7.1.1 and 7.1.2 adjusted for additional site preparation as described above:

Construction Camp Cost =

$$0.266 \times (\text{Net Capacity})^{0.5} + 0.110 \times (\text{Net Capacity})^{0.78}$$

If this adjustment is used, the adjustment above for loss of labor productivity should not be applied.

#### 7.1.4 Interest During Construction

To calculate interest during construction for a power plant for an interest rate,  $r$ , multiply the capital costs from Sections 7.1.1, 7.1.2, and 7.1.3 by the following factor:

$$\text{IDC Factor} = (1 + r)^{TM} - 1$$

where  $TM$  is the time (in years) from the centroid of expenditures to commercial operation.  $TM$  can be approximated as follows:

$$TM = 0.439 \times (\text{Net Capacity})^{0.208}$$

## 7.2 POWER PLANT O&M COSTS

The annual O&M costs for a geothermal power plant may be estimated as follows:

$$\text{O\&M Costs} = \frac{0.65}{N} + 1.12 \times C_1 \times \text{COST}_1$$

where  $N$  is the number of power plants operated by one staff of operating personnel,

$C_1$  is a factor that reflects the service severity for the power plant ( $C_1 = 0.03$  for low and probable cost situations, and  $C_1 = 0.05$  for high cost service), and

$\text{COST}_1$  is the power plant capital cost, as determined in Sections 7.1.1, 7.1.2, and 7.1.3.

### 7.3 CAPITAL COSTS FOR WELLFIELD SURFACE FACILITIES

The cost estimates in this section are for wellfield surface facilities only. They do not include the cost of wells. To estimate the number of wells, the total production flow rate must be known; this can be estimated using the geothermal fluid rate from Section 2.5.

#### 7.3.1 Production Facilities

The capital costs for low, probable, and high cost wellfield production surface facilities as a function of power plant net capacity may be estimated as follows:

$$\text{Cost} = a_2 \times (\text{Net Capacity})^{b_2}$$

The values for the coefficient,  $a_2$ , and the exponent,  $b_2$ , are given in Table 7-2.

The low, probable, and high cost configurations for the production surface facilities are as follows:

- o Low cost. All production wells are located on one production island near the power plant. The wells are directionally drilled.
- o Probable cost. The production wells are located on production islands with up to six wells per production island. The wells are directionally drilled.
- o High cost. The production wells are uniformly distributed over the production field. The wells are drilled vertically.

#### 7.3.2 Reinjection Facilities

The capital costs for probable and high cost reinjection surface facilities may be estimated as follows:

$$\text{Cost} = a_3 \times (\text{Net Capacity})^{b_3}$$

The values for the coefficient,  $a_3$ , and the exponent,  $b_3$ , are given in Table 7-3.

Table 7-2

COEFFICIENTS AND EXPONENTS FOR WELLFIELD PRODUCTION SURFACE  
FACILITIES COST EQUATION

Resource Type	Resource Temperature (°F)	Power Plant Type	Low Cost		Probable Cost		High Cost	
			a <sub>2</sub>	b <sub>2</sub>	a <sub>2</sub>	b <sub>2</sub>	a <sub>2</sub>	b <sub>2</sub>
Steam	N/A	Direct steam	0.465	0.762	0.708	0.762	0.708	0.762
Hot water	530	Single flash	0.303	0.771	0.178	1.000	0.232	0.988
Hot water	530	Double flash	0.254	0.798	0.146	1.035	0.200	1.016
Hot water	420	Single flash	0.367	0.777	0.199	1.039	0.269	1.026
Hot water	420	Double flash	0.331	0.780	0.200	0.996	0.250	0.993
Hot water	350	Double flash	0.461	0.749	0.262	0.991	0.333	0.989
Hot water	350	Binary	0.297	0.675	0.140	0.996	0.194	0.983

Table 7-3

COEFFICIENTS AND EXPONENTS FOR WELLFIELD REINJECTION SURFACE  
FACILITIES COST EQUATION

Resource Type	Resource Temperature (°F)	Power Plant Type	Probable Cost		High Cost	
			a <sub>3</sub>	b <sub>3</sub>	a <sub>3</sub>	b <sub>3</sub>
Steam	N/A	Direct steam	0.862	0.152	0.862	0.152
Hot water	530	Single flash	0.470	0.700	0.535	0.715
Hot water	530	Double flash	0.383	0.700	0.394	0.743
Hot water	420	Single flash	0.783	0.700	0.797	0.729
Hot water	420	Double flash	0.640	0.700	0.672	0.726
Hot water	350	Double flash	0.982	0.700	0.997	0.726
Hot water	350	Binary	1.074	0.700	1.103	0.719

The low, probable, and high cost configurations for the reinjection surface facilities are as follows:

- o Low cost. ReInjection is not required. The cost of disposal facilities for geothermal liquids is assumed to be insignificant.
- o Probable cost. For steam resources, the reinjection system is typical of that in current use at The Geysers. For hot water resources, all reinjection wells are located on one reinjection island one mile from the power plant. The wells are directionally drilled.
- o High cost. For steam resources, the reinjection system is typical of that in current use at The Geysers. For hot water resources, the reinjection wells are uniformly distributed over the reinjection field. The center of the reinjection field is one mile from the power plant. The wells are drilled vertically.

### 7.3.3 Adjustments

Terrain. For mountainous terrain, adjustments may be needed to account for loss of labor productivity and for additional site preparation costs as follows:

- o Loss of labor productivity. Multiply the sum from Sections 7.3.1 and 7.3.2 by the factor 1.02. (This adjustment should not be used if the cost of a construction camp is added for areas with inadequate local construction labor, as explained below.)
- o Additional site preparation. Multiply the sum from Sections 7.3.1 and 7.3.2 by the factor 1.02.

Inadequate Local Construction Labor. For situations where a construction camp is needed, add the following to the sum from Sections 7.3.1 and 7.3.2, adjusted for additional site preparation as described above:

Construction Camp Cost =

$$0.109 \times (\text{Net Capacity})^{0.5} + 0.037 \times (\text{Net Capacity})^{0.78}$$

If construction camp cost is included, the adjustment described above for loss of labor productivity should not be applied.

Since the wellfield surface facilities and the power plant are usually built by separate organizations, construction camp costs should be added to each. These costs for a power plant are addressed in Section 7.1.3.

#### 7.3.4 Interest During Construction

To calculate interest during construction for the wellfield surface facilities for an interest rate,  $r$ , multiply the capital costs from Sections 7.3.1, 7.3.2, and 7.3.3 by the following factor:

$$\text{IDC Factor} = (1 + r)^{TM} - 1$$

where  $TM$  is the time (in years) from the centroid of expenditures to commercial operation.  $TM$  can be approximated as follows:

$$TM = 0.439 \times (\text{Net Capacity})^{0.208}$$

#### 7.4 O&M COSTS FOR WELLFIELD SURFACE FACILITIES

The annual O&M costs for geothermal wellfield surface facilities may be estimated as follows:

$$\text{O\&M Costs} = \frac{0.73}{M} + 1.12 \times C_2 \times \text{COST}_2 + E \times CF \times K \times (\text{Net Capacity})$$

where  $M$  is the number of wellfields operated by one staff of operating personnel,

$C_2$  is a factor that reflects the service severity for the wellfield surface facilities. (For steam resources,  $C_2 = 0.04$  for low and probable cost service, and  $C_2 = 0.06$  for high cost service. For hot water resources,  $C_2 = 0.06$  for low and probable cost service, and  $C_2 = 0.08$  for high cost service.),

$\text{COST}_2$  is the capital cost for the wellfield surface facilities, as determined in Sections 7.3.1, 7.3.2, and 7.3.3,

$E$  is the cost of electric energy in cents/kWh,

$CF$  is the capacity factor ( $0 < CF \leq 1.0$ ), and

$K$  is a pumping power factor proportional to the power requirement for operating the wellfield for each type of power plant, as given in Table 7-4.

Table 7-4

## PUMPING POWER FACTOR, K

<u>Resource Type</u>	<u>Resource Temperature (°F)</u>	<u>Power Plant Type</u>	<u>Low Cost</u>	<u>Probable Cost</u>	<u>High Cost</u>
Steam	N/A	Steam	0	0	0
Hot water	530	Single flash	0	0.000992	0.00198
Hot water	530	Double flash	0	0.000734	0.00147
Hot water	420	Single flash	0	0.00210	0.00420
Hot water	420	Double flash	0	0.00156	0.00311
Hot water	350	Double flash	0	0.00292	0.00585
Hot water	350	Binary	0.00339	0.00678	0.0135

The annual maintenance costs for the production and reinjection wells are not included in these O&M cost estimates. The O&M costs presented here are for wellfield operation and for maintenance of the surface facilities only.

## 7.5 COSTS OF BIPHASE POWER MODULES

### 7.5.1 Power Plant Capital Costs

Capital cost estimates for Biphasic power modules and wellfield production surface facilities are given in Table 7-5. Interest during construction is included in these estimates. For installations where larger capacity is needed, a number of modules, each having the individual output capacity indicated for the resource temperature of interest, would be used to achieve the required capacity.

Capital costs of H<sub>2</sub>S abatement facilities can be estimated using the procedure in Section 7.1.2.

Table 7-5

CAPITAL COST ESTIMATES  
FOR BIPHASE MODULES

<u>Item</u>	<u>Resource Temperature</u>		
	<u>350°F</u>	<u>420°F</u>	<u>530°F</u>
Module Capacity - MWe (net)	4.50	9.80	18.20
Cost of Power Plant and Wellfield Production Surface Facilities <sup>(a)</sup> - \$million	6.53	10.58	15.83

(a) One production well is required or all production wells are drilled from one production island.

#### 7.5.2 Power Plant O&M Costs

O&M costs for Biphase power plant modules can be estimated as discussed in Section 7.2. One operating crew could be expected to operate up to seven generating modules.

#### 7.5.3 Capital Costs for Wellfield Surface Facilities

Capital cost estimates for wellfield production surface facilities are included in the estimates for Biphase modules in Table 7-5. Capital cost estimates for the wellfield reinjection surface facilities are given in Table 7-6. Interest during construction is included in these estimates.

Table 7-6

CAPITAL COST ESTIMATES FOR WELLFIELD REINJECTION  
SURFACE FACILITIES FOR BIPHASE MODULES

<u>Item</u>	<u>Resource Temperature</u>		
	<u>350°F</u>	<u>420°F</u>	<u>530°F</u>
Module Capacity - MWe (net)	4.50	9.80	18.20
Wellfield ReInjection Surface Facilities - \$million			
o Low Cost	0	0	0
o Probable Cost	0.22	0.20	0.22
o High Cost	0.47	0.42	0.46

#### 7.5.4 O&M Costs for Wellfield Surface Facilities

O&M costs for wellfield surface facilities can be estimated using the procedure in Section 7.4; however, the term for cost of pumping power is zero when Biphase power plant modules are used.

### 7.6 COSTS OF ORMAT POWER UNITS

#### 7.6.1 Power Plant Capital Costs

A capital cost estimate for Ormat binary cycle units to produce 10 MWe (net) is \$14 million. The cost of the Ormat units is virtually the same over the range of resource temperatures from 250 to 350°F as discussed in Section 2.8.

Abatement equipment for H<sub>2</sub>S would not be required because in a binary plant the H<sub>2</sub>S is never allowed to separate from the geothermal water before it is reinjected.

Interest during construction can be estimated using the procedure in Section 7.1.4 with TM equal to 0.333.

#### 7.6.2 Power Plant O&M Costs

O&M costs estimated by Ormat Systems Inc. are \$700,000 per year for a 10 MWe (net) plant.

#### 7.6.3 Capital Costs for Wellfield Surface Facilities

The procedure in Section 7.3, with the adjustments described below for the required flow rates of geothermal water, can be used to estimate the capital costs for wellfield production and reinjection surface facilities.

First, capital cost estimates are calculated, using Section 7.3, for a 10 MWe (net) binary plant.

Then, adjustments in the form of multiplying factors are calculated as follows:

o Production surface facilities

$$\text{Adjustment factor} = \left( \frac{\text{FLOW}}{1.71} \right)^{b_2}$$

o Reinjection surface facilities

$$\text{Adjustment factor} = \left( \frac{\text{FLOW}}{1.71} \right)^{b_3}$$

where  $b_2$  and  $b_3$  are exponents as defined in Section 7.3 and FLOW equals 1.55 for a 350°F resource, 2.40 for a 300°F resource, and 4.50 for a 250°F resource.

Finally, the estimates from the procedure in Section 7.3 are multiplied by the corresponding adjustment factors calculated above.

Interest during construction can be estimated using the procedure in Section 7.3.4 with TM equal to 0.333.

#### 7.6.4 O&M Costs for Wellfield Surface Facilities

O&M costs for wellfield surface facilities can be estimated using the procedure in Section 7.4. For the Ormat units, the pumping factor K should be multiplied by the factor FLOW/1.71, where FLOW is as defined and evaluated in Section 7.6.3 above.



## Section 8

### REFERENCES

- 1-1 Technology Evaluation Group, Technical Assessment Guide, Electric Power Research Institute, Palo Alto, California, EPRI P-2410-SR, May 1982.
- 3-1 Advertisement by Sacramento Municipal Utility District, Geothermal Resources Council Bulletin, December 1983, p. 30.







## APPENDIX 6

### WELLHEAD Program

- o Summary
  - o Program Operation and Listing
  - o Engineering Analysis of Organic Rankine Cycle - Computer Program (ODOE 1983)
- Binary Generation Economic Analysis - Computer Program (ODOE 1983)



## SUMMARY

### Wellhead Binary Generator Analysis

The Geo-Heat Center of the Oregon Institute of Technology was recently under contract to the Oregon Department of Energy to assist in the evaluation of the operation of binary generators located at Lakeview, Oregon. Part of that contract was the development of a computer program related to the production of electricity using the Organic Ranking Cycle to convert the energy in low temperature geothermal water 82-150°C (180-300°F). The program consisted of an engineering analysis that predicts net hourly saleable power based on key input parameters and a generic type economic analysis based on the engineering output and additional parameters. To simplify operation of the economic evaluation program, the engineering calculations were included in the second part. Nominal machine size and average net saleable power are included in the program.

The original program was written for use on the Texas Instrument TI-59 hand held computer, and also was placed in spreadsheet format using Visicalc (TM VisiCorp) and an Apple III computer. The program developed by Ryan, 1984 is in the Perfect Calc (TM Perfect Software) form. The final product is in LOTUS 123 (TM) and can be readily adapted to other spreadsheet programs. The appendix contains reports documenting the original calculations.

Well capital costs are based on a simple, adjustable dollars per foot formula. It was felt that wells drilled for wellhead binary facilities will be more akin to large volume irrigation wells than steam wells. Capital costs for geothermal piping are based on geothermal water flow. Capital costs for the wellhead binary generator and the cooling tower system are based on the calculated nominal machine size. The program was intentionally designed to determine power from one well, i.e., less than 2 MW in size given the prescribed temperatures. Contingency and engineers fee (10 percent) is an added capital cost. An inflation multiplier is built into the program and capital costs adjusted from the original date of the program, June 1983.

While this program can be modified to allow remaining assessment work, dry holes, and transmission line costs to be added, it was created without them. The program was developed based on the project at Lakeview, Oregon. At that site, assessment work was completed, to a degree, by the well owner but not by the power plant developer. No dry

holes were encountered there. And finally, the site is only several hundred feet from power lines. It is concluded that any potential wellhead binary sites will need similar site advantages for project feasibility.

Maintenance costs for the binary generator, cooling tower system, geothermal water piping, and well pump maintenance are based on percentages of capital cost (including proration of the contingency and engineers fee). Respective percentages for the above are: 5 percent, 3 percent, 1 percent, and 5 percent. No maintenance cost is applied to the wells. Taxes (1 percent), insurance (1/2 percent), and operating cost are based on total capital investment, excluding well costs. The program provides for both public entities which do not pay property taxes and taxable private operators. Purchased geothermal energy can be introduced into the program and treated as an operating cost, based on prices specified as an input.

Annual electrical sales (\$/yr) are based on average net saleable power (kW) and 7,884 hours of operation per year. Annual gross income is the sum of electrical sales (\$/yr) and any annual geothermal effluent sales (\$/yr). Effluent sale is based on geothermal water flow rate and price (\$/1,000 gal) as specified as an input. Annual net income is gross income less total operating cost. Simple payback is total capital investment (\$) divided by annual net income (\$/yr).

WELLHEAD Cost Estimates

<u>Site</u>	<u>Resource Temp.(°C) 1</u>	<u>Flow Rate (GPM) 2</u>	<u>Static Water Level (ft.) 3</u>	<u>Net Plant Size (KW) 4</u>	<u>Estimated Capital Cost (\$/Net KW) 5</u>
Cove & Crane Cr., ID	163	750	100	1810	2099
Big Creek HS, ID	163	750	0	1679	2177
Vulcan HS, ID	160	750	0	1706	2215
Raft River area, ID	147	1100	20	1989	2621
Ennis, MT	129	750	100	1006	2963
Lakeview area, OR	144	750	95	1249	3007
Summer Lake HS, OR	142	750	140	1209	3101
Hallinan Springs, OR	140	750	21	1173	3181
Boulder HS, MT	136	750	100	1155	3221
Fischer HS, OR	139	750	15	1151	3232
Barry Ranch HS, OR	139	750	115	1148	3241
Deer Creek HS, ID	139	750	0	1089	3236
Magic HS, ID	140	750	100	1030	3466
Roystone HS, ID	135	750	0	958	3543
Baker HS, WA	139	750	115	1086	3727
Owl Creek HS, ID	123	750	0	932	3760
Jackson HS, MT	125	750	100	925	3792
Mt. Hood, OR	134	750	115	1144	3899
White Arrow, ID	120	750	100	764	4247
Gregson HS, MT	118	750	100	762	4289
Broadwater HS, MT	118	750	100	748	4327
Indian Creek HS, ID	119	750	100	729	4365
Squaw Creek HS, ID	119	750	100	743	4423
Crane HS, OR	117	750	50	724	4502
Luce HS, OR	118	750	100	667	4682
Sharkey HS, ID	114	750	0	646	4718
Bonneville HS, ID	109	750	0	612	4916
Belknap HS, OR	113	750	100	601	4916
Battle Creek HS, ID	113	750	100	624	4933



# WELLHEAD Cost Estimates

(cont'd)

Little Valley area, OR	114	750	100	597	5025
O.J. Thomas well, OR	102	1000	0	627	5035
Umpqua HS, OR	117	750	100	711	5132
Norris HS, MT	107	750	100	547	5236
Marysville well, MT	122	750	1740	532	5471
Beulah HS, OR	113	750	100	624	5595
Cabarton HS, ID	105	750	0	474	5680
Riggins HS, ID	100	750	0	437	5981
Maple Grove HS, ID	103	750	100	431	6012
Barron's HS, ID	103	750	0	422	6079
Murphy Hot Springs, ID	103	750	100	422	6079
Krigbaum HS, ID	102	750	0	420	6103
Blue Mountain HS, OR	108	750	100	538	6179
Weberg HS, OR	108	750	100	538	6179
Breitenbush HS, OR	109	750	100	528	6232
Boiling HS, ID	99	750	0	363	6672
Foley HS, OR	100	750	100	362	6677
Ben Meek Well, ID	98	750	100	334	7232
Rustler Peak, OR	100	750	100	422	7254
Latty HS, ID	98	750	0	314	7288
Bigelow HS, OR	97	750	100	310	7351
Guyer Hot Springs, ID	96	750	0	308	7379
Sunbeam HS, ID	93	750	0	291	7636
Cougar Peak, OR	100	750	0	385	7704
Devils Garden area, OR	100	750	100	385	7704
Diamond Craters, OR	100	750	100	385	7704
Four Craters area, OR	100	750	100	385	7704
Squaw Ridge area, OR	100	750	100	385	7704
China Hat/East Butte, OR	100	750	100	377	7803
Frederick Butte, OR	100	750	100	377	7803
Quartz Mountain, OR	100	750	100	377	7803
Austin HS, OR	101	750	100	351	8165
Jackies Butte Field, OR	100	750	100	347	8242
Jordan Craters area, OR	100	750	100	347	8242



# WELLHEAD Cost Estimates

(cont'd)

McCredie HS, OR	98	750	100	321	8710
Cropp HS, OR	96	750	15	302	9084
Medical HS, OR	96	750	50	302	9084
Kahneeta HS, OR	96	750	50	296	9216
Mitchell Butte HS, OR	93	750	16	217	9585
Worswick HS, ID	90	750	0	200	9785
McDermitt area, OR	91	750	100	187	10639
Wall Creek WS, OR	93	750	100	227	11129
Big Southern Butte, ID <sup>6</sup>	--	--	--	--	--
Blackfoot Lava Field, ID <sup>6</sup>	--	--	--	--	--
Island Park Caldera, ID <sup>6</sup>	--	--	--	--	--
Mt. Adams, WA <sup>6</sup>	--	--	--	--	--
Mt. Baker, WA <sup>6</sup>	--	--	--	--	--
Puny Creek, WA <sup>6</sup>	--	--	--	--	--
Rexburg Caldera, ID <sup>6</sup>	--	--	--	--	--
Shukash Basin, OR <sup>6</sup>	--	--	--	--	--
Silver Star, MT <sup>6</sup>	--	--	--	--	--
White Licks HS, ID <sup>6</sup>	--	--	--	--	--

Total Sites: 81

<sup>1</sup> Either measured or most likely geothermometer estimate.

<sup>2</sup> 750 gpm default value, unless better data.

<sup>3</sup> 100 foot default value, unless better data.

<sup>4</sup> Parastatic loads vary, hence net power is presented here. See App. 5 for site specific data.

<sup>5</sup> Costs include well, piping and plant.

<sup>6</sup> Insufficient data available.

## I. What is WELLHEAD?

The WELLHEAD computer program is used to estimate the capital costs for a given geothermal resource. The estimates are based upon the temperature, the flow rate, and the location of the source. It is very similar to the CENTPLANT program except these calculations are tailored for geothermal sources of lower temperatures (180-300F) than the sources used in the CENTPLANT program.

WELLHEAD was originally developed by Gene Ryan who, at that time, worked with Oregon Institute of Technology under a contract with the Oregon Department of Energy. The original version was written as a Multiplan program. This version is a translation of the original and is designed to run as a LOTUS spreadsheet program using a COMPAQ computer with MS.DOS 2.0 operating system.

The assumptions and equations used for these calculations should be referenced to the manual as there is no documentation in the code concerning such matters. This document is only to help a user or programmer get to the program - not to analyze it.

## II. Starting the Program

The program is located on the disk at the back of this manual. It is titled WELLHEAD. Remember that you must be LOTUS to use this program. So follow these steps to start the program.

1. Put the WELLHEAD disk in drive B of your computer. (Or copy the program to the harddisk if you are using a computer with a harddisk. You will also need to change the default drive setting in LOTUS to recognize the harddisk. The rest of this explanation assumes that you are using a dual floppy disk system).

2. Insert the LOTUS program disk in Drive A and start a new Lotus 123 spreadsheet application.

3. Using the File Retrieve command in LOTUS, select the WELLHEAD program. When the WELLHEAD program is retrieved, you will be ready to use it for calculations.

(Note: a backup copy of the WELLHEAD disk is kept in the data processing office. Should this WELLHEAD disk become damage or lost, you can make a copy of the backup disk and continue with your calculations. However, you should never use the backup disk, it should only be copied. )

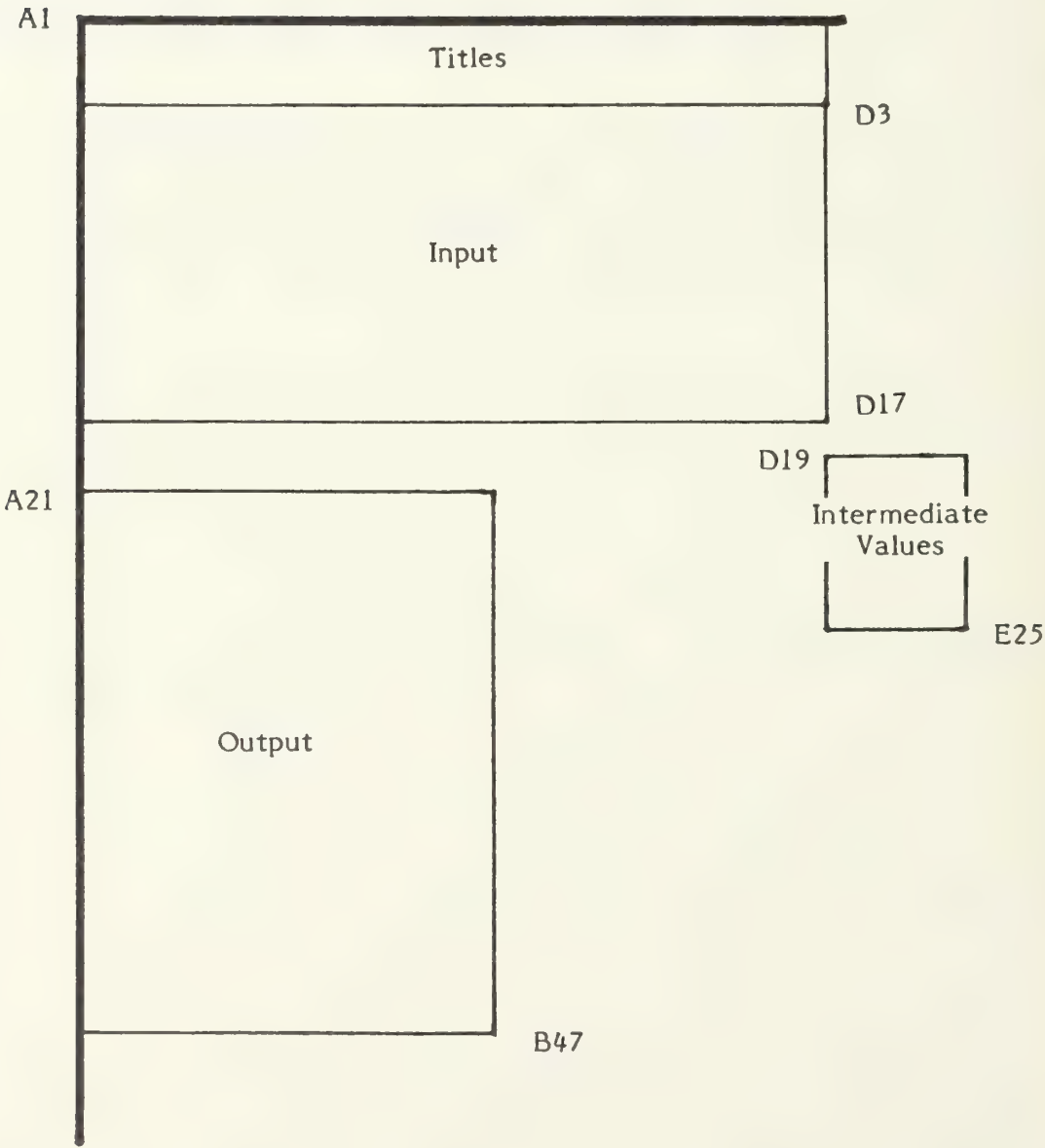
### III. Using the program.

The WELLHEAD spreadsheet is relatively simple. There is an input section, an intermediate section, and an output section. The input section is located in the upper left hand corner of the spreadsheet. (see the spreadsheet map on the following page) Directly below the input section is the output section. Both the input and the output sections have several parameters.

Altering the variables in the input section will automatically alter the output values. (Make sure the calculation setting for the LOTUS program is set to automatic if changes in the output are not occurring.) The input section is the only place you should try to modify values.

WELLHEAD

SPREADSHEET MAP



# CODE LIST

A1: 'BINARY GENERATOR ECONOMIC ANALYSIS  
 B1: ' values  
 C1: 'units  
 D1: '  
 A2: 'WSED Ver.2 JDM 20Feb85  
 A3: ' INPUT  
 A5: 'Production Well Depth (ft)  
 B5: 6560  
 C5: 'feet  
 A6: '(Injection well)oldval  
 B6: 1  
 C6: 'oldval  
 A7: 'Property taxes (pub=1,priv=3)  
 B7: 3  
 A8: 'Geothermal Water Temperature  
 B8: 282  
 C8: 'Deg F  
 A9: 'Geothermal Water Flow Rate  
 B9: 750  
 C9: 'gpm  
 A10: 'Avg Annual Wet Bulb Temperature  
 B10: 40  
 C10: 'Deg F  
 A11: 'Static Water Level, Inj Well  
 B11: 115  
 C11: 'feet  
 A12: 'Pumping level, production well  
 B12: 215  
 C12: 'feet  
 A13: 'Month of the year (number)  
 B13: 1  
 C13: 'month  
 A14: 'Last two digits of year  
 B14: 85  
 C14: 'year  
 A15: '(Purch Fluid--unit cost)oldval  
 B15: 0  
 C15: 'oldval  
 A16: 'Effluent sold (unit cost)  
 B16: 0  
 C16: '\$/1000gal  
 A17: '(Elec Sold--unit cost) oldval  
 B17: 0.07  
 C17: 'oldval  
 D19: 'intermed  
 E19: ' values  
 D20: '\$/foot  
 E20: 100  
 A21: ' OUTPUT  
 D21: 'temp-172  
 E21: +B8-172  
 A22: 'Nominal Machine Size

CODE LIST (Continued)

B22:  $(2.088 - (0.032 * E22)) * B9 * (B8 - 172) / 128 * 1.4$   
D22: 'wblb-30  
E22: +B10-30  
A23: 'Well Pumping Power  
B23:  $((@ABS(B12 - 2 * B11) + B12 - 2 * B11) / (1 + B6)) * B6 + 51 + B12) * E23 / 1725895$   
D23: '8640\*etc  
E23:  $8640 * B9 / ((0.0000015774 * B8^2.075 + 2.301) * 7.481)$   
A24: 'Avg Net Saleable Power  
B24: +B22/1.4-B23  
D24: 'prstcld  
E24: +B22-B23-B24  
A25: 'Inflation Multiplier (6/B3base)  
B25:  $(F5) ((B14 - 83) * 12 + (B13 - 6)) * 0.00583 + 1$   
D25: 'flow-300  
E25: +B9-300  
A26: 'Binary Gen. Capital Cost  
B26:  $(1800 - (B8 - 180) * 8.5714) * B22 * B25$   
A27: 'Cooling Tower Capital Cost  
B27:  $((E22 * 0.568) + 33.97) * 8.33 * B22 * B25$   
A28: 'Source Water Piping Cap. Cost  
B28:  $(E25 * 83.286 - E25^1.1129 * 27.898 + 40000) * B25$   
A29: 'Source Well Pump Capital Cost  
B29: +B23\*800\*B25  
A30: 'Source Well Capital Cost  
B30: +B5\*100  
A31: 'Injection Well Capital Cost  
B31: +B5\*100  
A32: 'Contingency & Engineers Fee  
B32:  $(B26 + B27 + B28 + B29 + B30 + B31) * 0.1$   
A33: 'Total Capital Cost  
B33: @SUM(B26..B32)  
A34: 'Binary Generator Maintenance  
B34: +B26\*0.055  
A35: 'Cooling Tower Maintenance  
B35: +B27\*0.033  
A36: 'Source Water Piping Maintenance  
B36: +B28\*0.011  
A37: 'Well Pump Maintenance  
B37: +B29\*0.055  
A38: 'Total Maintenance  
B38: @SUM(B34..B37)  
A39: 'Taxes & Insurance  
B39:  $(B33 - 1.1 * (B30 + B31)) * 0.005 * B7$   
A40: 'Annual Cost of Purchased Fluid  
B40: +B9\*B15\*8760/1000\*60\*0.9  
A41: 'Total Operating Cost, 1st Year  
B41: +B38+B39  
A42: 'Net Annual Electricity Sales  
B42: '  
A43: 'Net Annual Effluent Sales  
B43: +B9\*B16\*8760\*60/1000\*0.9  
A44: 'Simple Capital Payback, pre-tax  
B44: +B33/((B24\*8760\*0.8)\*0.05)  
A46: 'Net installed kw cost w/wells  
B46: +B33/B24  
A47: 'Net installed kw cost w/o wells  
B47:  $(B33 - B30 - B31) / B24$

This is a sample of the entire WELLHEAD Spreadsheet.

BINARY GENERATOR ECONOMIC ANALYSIS      values units  
WSEO Ver.2      JDM 20Feb85  
INPUT

Production Well Depth (ft)	6560 feet
(Injection well)oldval	1 oldval
Property taxes (pub=1,priv=3)	3
Geothermal Water Temperature	282 Deg F
Geothermal Water Flow Rate	750 gpm
Avg Annual Wet Bulb Temperature	40 Deg F
Static Water Level, Inj Well	115 feet
Pumping level, production well	215 feet
Month of the year (number)	1 month
Last two digits of year	85 year
(Purch Fluid--unit cost)oldval	0 oldval
Effluent sold (unit cost)	0 \$/1000gal
(Elec Sold--unit cost) oldval	0 oldval

		intermed	values
		\$/foot	100
OUTPUT		temp-172	110
Nominal Machine Size	1595	wblb-30	10
Well Pumping Power	54	8640*etc	347518
Avg Net Saleable Power	1086	prstcld	456
Inflation Multiplier (6/83base)	1.11077	flow-300	450
Binary Gen. Capital Cost	1640426		
Cooling Tower Capital Cost	585284		
Source Water Piping Cap. Cost	58267		
Source Well Pump Capital Cost	47595		
Source Well Capital Cost	656000		
Injection Well Capital Cost	656000		
Contingency & Engineers Fee	364357		
Total Capital Cost	4007929		
Binary Generator Maintenance	90223		
Cooling Tower Maintenance	19314		
Source Water Piping Maintenance	641		
Well Pump Maintenance	2618		
Total Maintenance	112796		
Taxes & Insurance	38471		
Annual Cost of Purchased Fluid	0		
Total Operating Cost, 1st Year	151267		
Net Annual Electricity Sales			
Net Annual Effluent Sales	0		
Simple Capital Payback, pre-tax	11		
Net installed kw cost w/wells	3691		
Net installed kw cost w/o wells	2483		



Computer Program - Part I

Engineering Analysis of  
Organic Rankine Cycle

ODOE Agreement #L50002

July 1983



## COMPUTER PROGRAM - PART I

### Engineering Analysis of Organic Rankine Cycle Oregon Department of Energy Lakeview Contract

#### INTRODUCTION

The Geo-Heat Center is currently under contract to the Oregon Department of Energy to assist in the evaluation of the operation of binary generators located at Lakeview, Oregon. Task 2 of this contract is the development of a three part computer program related to the production of electricity using the Organic Rankine Cycle to convert the energy in low temperature geothermal water (approximately 180°F to 250°F). This report is concerned with Part I of Task 2, an engineering analysis that predicts net hourly saleable power based on key input parameters. Part 2 and Part 3, to be covered in later reports, will be: (Part 2) a generic type economic analysis; and (Part 3) an evaluation of the riffle cooling system performance.

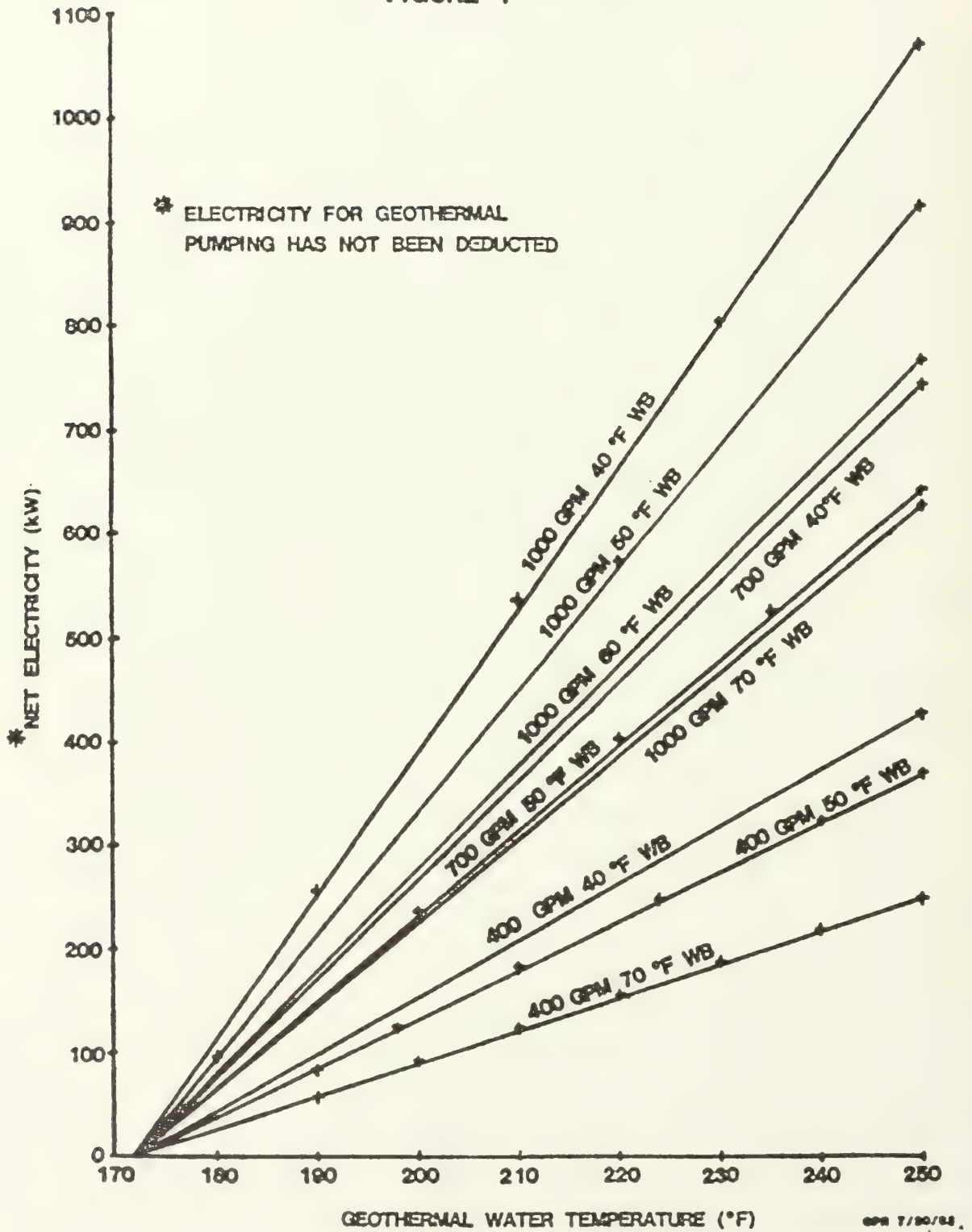
#### METHODOLOGY

First, a series of curves were developed that plot electricity output from the generator as a function of geothermal water temperature. Each of the individual curves were determined at a specified geothermal water flow rate and a specified wet bulb temperature. Figure 1 shows the curves that were used. Net electricity in Figure 1 has not been reduced by the electricity required to pump the geothermal water. This electricity is accounted for later. Using curves on Figure 1, mathematical relationships were developed that match the curves. These relationships were programmed in Texas Instrument language (TI-59). In addition, a relationship was programmed that computes the geothermal pumping electricity. This pumping electricity was deducted, and the computer program yields the net hourly saleable power.

Figure 1 was developed based on rigorous calculation of the points indicated by + on the figure. An example of a single point calculation input data and calculated results are shown on Table 1. The basis for these calculations follows.

# NET ELECTRICITY VS GEOTHERMAL TEMPERATURE

FIGURE 1



# TYPICAL SINGLE POINT CALCULATION SUMMARY

TABLE 1

## INPUT

01	Geothermal Water Temp. at Evaporator. (°F)	250
02	Geothermal Effluent Temp. at Evaporator. (°F)	172
03	Wet Bulb Temperature. (°F)	50
04	Evaporator & Condenser Approach Temp. (°F)	12
05	Cooling Water Delta T. (°F)	13
06	Geothermal Water Flow Rate @ Hot Temp. (gpm)	700
07	Expander Efficiency. (decimal)	.8
08	C.W. & R114 Pump Efficiency X Motor Efficiency (decimal)	.54
09	Total Delta P (R114) Evap., Cond. & Pipe.(psi)	15
10	Generator Efficiency. (decimal)	.9
11	Total Delta P (R114) Cooling Water System. (psi)	15
12	C.W. Fan Power. (kW/10 <sup>6</sup> Btu/hr)	1.65
13	Well Pump Wire to Water Efficiency. (decimal)	.65
14	Well Pump Head (lift + piping + evap.). (ft)	0

## OUTPUT

16	Max. Geothermal Water Delta T Preheater. (°F)	32.53566101
17	Evaporator Sat. Liquid Enthalpy. (Btu/lb R114)	47.29638476
18	Evaporator Temp. (°F)	160
19	Condenser Temp. (°F)	83
20	Evaporator Pressure. (psia)	109.632
21	Evaporator Sat. Vapor Enthalpy. (Btu/lb R114)	93.212
22	Evaporator Sat. Vapor Entropy. (Btu/lb R)	.16504
23	Condenser Pressure. (psia)	34.5129687
24	Condenser Sat. Liquid Enthalpy. (Btu/lb R114)	27.59559575
25	Condenser Sat. Vapor Enthalpy. (Btu/lb R114)	82.18184977
26	Condenser Sat. Vapor Entropy. (Btu/lb R)	.1579332165
27	Expanded Vapor Enthalpy. (Btu/lb R114)	86.15563621
28	Theo. Heat to Cycle. (Btu/lb R114)	65.61640425
29	Theo. Heat to Expander. (Btu/lb R114)	7.056363791
30	Theo. Heat to Cooling (Btu/lb R114)	58.56004046
31	Theo. Cycle Efficiency. (decimal)	.1075396293
32	Cooling Water In. (°F)	58
33	Cooling Water Out. (°F)	71
34	Cooling Water Flow Rate. (gpm)	5008.559017
35	Cooling Tower Duty. (Btu/hr)	32680870.56
36	Heat from Geothermal Water. (Btu/hr)	35471966.72
37	Heat Loss from Binary Machine. (Btu/hr)	714850.5478
38	Heat to Refrigerant. (Btu/hr)	35757116.18
39	Theo. Heat to Cooling. (Btu/hr)	31911809.16
40	Theo. Heat to Expander. (Btu/hr)	3845307.019
41	Expander Heat Rejection. (Btu/hr)	769061.4039
42	R114 Circulation Rate. (gpm)	752.6970014
43	Pumping Loss Condenser to Evap. (Btu/hr)	155435.7438
44	Total Refrigerant Flow Losses. (Btu/hr)	31039.57024
45	Binary Shaft Output. (Btu/hr)	3076245.616
46	Generator Loss. (Btu/hr)	307624.5616
47	Gross Available Electricity. (kW)	756.5618928
48	Cooling Tower Fan Usage. (kW)	53.92343643
49	Cooling Tower Pumps Usage. (kW)	60.51376975
50	Well Pump & Geothermal System Usage. (kW)	0
51	Net Power Available for Sales. (kW)	642.1246866
52	Preheater Duty. (Btu/hr)	10735354.86
53	C.W. Conversion psi to Ft. (ft/psi)	2.301
54	Geo. Effluent Temp. at Preheater. (°F)	139.464339
55	Overall Thermal Efficiency. (decimal)	.0600892069
56	Evaporator Duty. (Btu/hr)	25021334.33
57	Geothermal Water Flow Rate. (lb/hr)	329956.5624
58	R114 Flow Rate. (lb/hr)	544941.7197
59	R114 Specific Gravity @ Pump. (lb/ft <sup>3</sup> )	90.26892622

## BASIS

Calculations were based on the use of refrigerant R-114 in a binary generation system using a preheater in series with the evaporator. A diagram of the flow configuration is shown on Figure 2. It was necessary to establish flow and performance criteria that could be expected from a competently designed binary system. The criteria used is as follows:

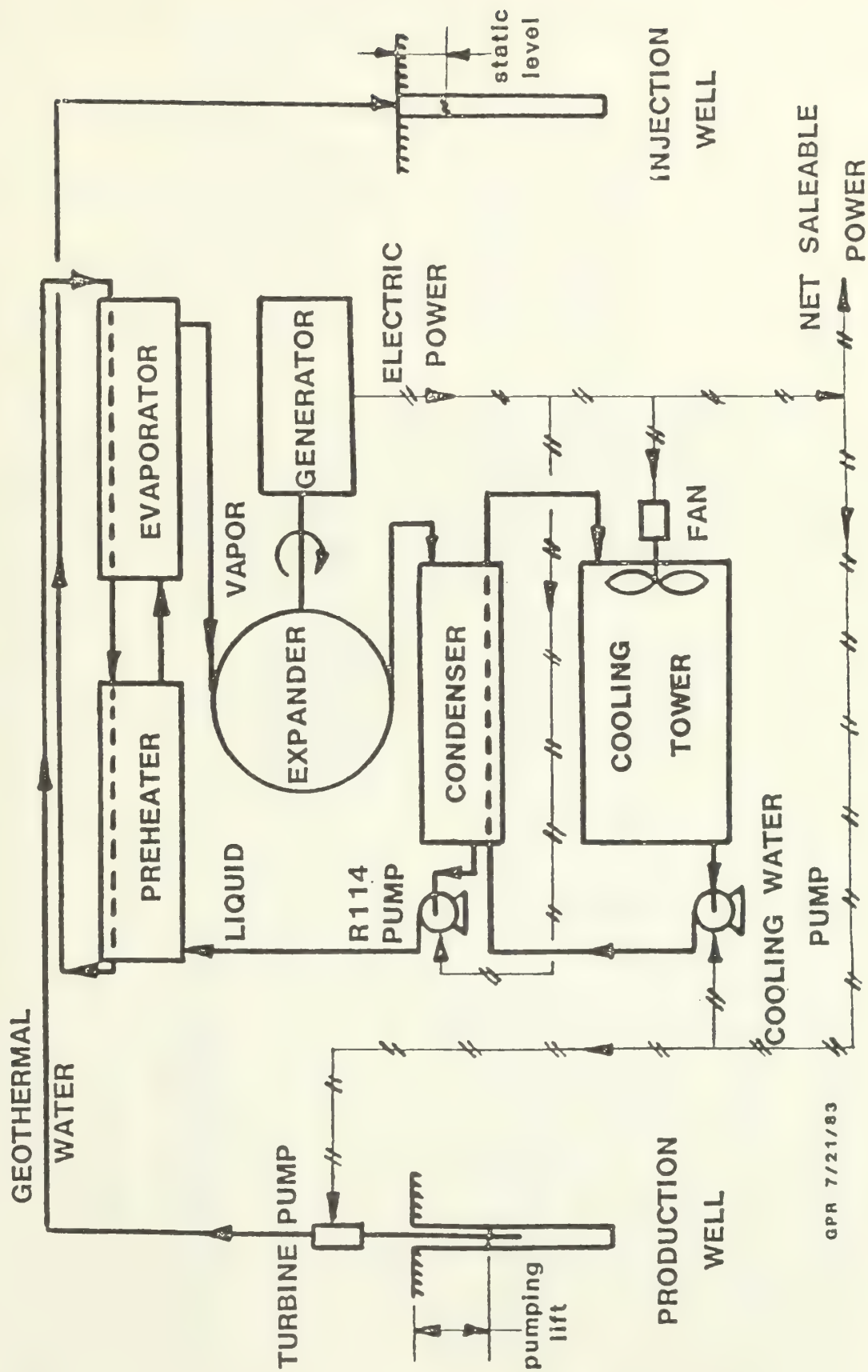
- (1) Evaporator temperature 160°F.
- (2) Maximum preheater duty without refrigerant vaporization in preheater.
- (3) Minimum condenser temperature of 60°F.
- (4) Evaporator and condenser approach temperature of 12°F.
- (5) Cooling water temperature rise of 13°F.
- (6) Expander efficiency @ 80%.
- (7) Cooling water pump and refrigerant pump efficiencies @ 60%.
- (8) Cooling water pump and refrigerant pump motor efficiencies @ 90%.
- (9) Total refrigerant flow pressure drop of 15 psi.
- (10) Cooling water fan power @ 1.65 kW per million Btu/hr of cooling.  
This is an average figure, based on use of multiple cooling tower cells or fan speed control to reduce power consumption at lower wet bulb conditions.
- (11) Well pump wire/water efficiency @ 65%.
- (12) Cooling water produced at an approach of 8°F to wet bulb temperature.
- (13) Generator efficiency @ 90%.
- (14) Cooling water system pressure drop of 15 psi.
- (15) Total pressure drop through geothermal system including injection.  
Piping and equipment = 51 feet of head (approximately 21 psi).  
Wells = (production well pumping lift X 2) - (injection well static head X 2), when [lift - (2 X static)] is positive.

## COMPUTER PROGRAM

The computer program calculates net hourly saleable electricity based on five items of input data. It also calculates nominal binary machine size to be used in Part 2 to determine capital cost. One of the items of

# SIMPLIFIED FLOW DIAGRAM BINARY POWER GENERATION

FIGURE 2



input data is the wet bulb temperature. For this program, the temperature used should be the average annual wet bulb temperature.

#### Input Data

- Store 01 Geothermal Water Temperature (°F)
- Store 02 Geothermal Water Flow Rate (gpm)
- Store 03 Annual Average Wet Bulb Temperature (40°F to 70°F limit)(°F)
- Store 04 Static Water Level in Injection Well (ft)
- Store 05 Pumping Water Level in Production Well (ft)

Run instruction: Enter one side of magnetic card in TI 59. Press RST and R/S.

#### Output Data

- Recall 06 Nominal Machine Size (kW)
- Recall 07 (and display) Average Hourly Net Saleable Electricity (kW)

If the program is run using a Texas Instrument PC-100C printer, the output will print out as shown on the example below.

235.  
700.  
43.  
100.  
200.  
810.  
530.

The program listing is shown below.

000	43	RCL	020	08	8	040	08	8
001	03	03	021	02	2	041	95	=
002	75	-	022	01	1	042	94	+/-
003	04	4	023	02	2	043	85	+
004	00	0	024	95	=	044	43	RCL
005	95	=	025	42	STD	045	40	40
006	45	Y%	026	40	40	046	85	+
007	01	1	027	43	RCL	047	01	1
008	93	.	028	03	03	048	93	.
009	06	6	029	75	-	049	00	0
010	05	5	030	04	4	050	06	6
011	01	1	031	00	0	051	09	9
012	08	8	032	95	=	052	09	9
013	95	=	033	65	×	053	02	2
014	65	×	034	93	.	054	95	=
015	93	.	035	00	0	055	65	×
016	00	0	036	01	1	056	43	RCL
017	00	0	037	05	5	057	02	02
018	00	0	038	06	6	058	95	=
019	00	0	039	02	2	059	55	÷

060 07 7  
 061 08 8  
 062 95 =  
 063 65 \*  
 064 53 ( )  
 065 43 RCL  
 066 01 01  
 067 75 -  
 068 01 1  
 069 07 7  
 070 02 2  
 071 54 )  
 072 95 =  
 073 42 STD  
 074 06 06  
 075 01 1  
 076 93 .  
 077 05 5  
 078 07 7  
 079 07 7  
 080 04 4  
 081 52 EE  
 082 06 6  
 083 94 +/-  
 084 65 \*  
 085 53 ( )  
 086 43 RCL  
 087 01 01  
 088 45 YX  
 089 02 2  
 090 93 .  
 091 00 0  
 092 07 7  
 093 05 5  
 094 54 )  
 095 95 =  
 096 85 +  
 097 02 2  
 098 93 .  
 099 03 3  
 100 00 0  
 101 01 1  
 102 95 =  
 103 42 STD  
 104 57 57  
 105 65 \*  
 106 07 7  
 107 93 .  
 108 04 4  
 109 08 8  
 110 01 1  
 111 95 =  
 112 35 1/X  
 113 65 \*  
 114 01 1  
 115 04 4  
 116 04 4  
 117 23 INV

118 52 EE  
 119 65 \*  
 120 06 6  
 121 00 0  
 122 95 =  
 123 65 \*  
 124 43 RCL  
 125 02 02  
 126 95 =  
 127 42 STD  
 128 57 57  
 129 02 2  
 130 65 \*  
 131 43 RCL  
 132 04 04  
 133 95 =  
 134 94 +/-  
 135 85 +  
 136 43 RCL  
 137 05 05  
 138 95 =  
 139 42 STD  
 140 40 40  
 141 33 X<sup>2</sup>  
 142 34 FX  
 143 85 +  
 144 43 RCL  
 145 40 40  
 146 95 =  
 147 55 +  
 148 02 2  
 149 95 =  
 150 85 +  
 151 43 RCL  
 152 05 05  
 153 95 =  
 154 85 +  
 155 05 5  
 156 01 1  
 157 95 =  
 158 65 \*  
 159 43 RCL  
 160 57 57  
 161 55 +  
 162 01 1  
 163 07 7  
 164 02 2  
 165 05 5  
 166 08 8  
 167 09 9  
 168 05 5  
 169 95 =

170 42 STD  
 171 07 07  
 172 94 +/-  
 173 85 +  
 174 43 RCL  
 175 06 06  
 176 95 =  
 177 42 STD  
 178 08 08  
 179 43 RCL  
 180 06 06  
 181 65 \*  
 182 01 1  
 183 93 .  
 184 04 4  
 185 95 =  
 186 42 STD  
 187 06 06  
 188 43 RCL  
 189 08 08  
 190 42 STD  
 191 07 07  
 192 00 0  
 193 42 STD  
 194 08 08  
 195 00 0  
 196 42 STD  
 197 09 09  
 198 43 RCL  
 199 01 01  
 200 99 PRT  
 201 43 RCL  
 202 02 02  
 203 99 PRT  
 204 43 RCL  
 205 03 03  
 206 99 PRT  
 207 43 RCL  
 208 04 04  
 209 99 PRT  
 210 43 RCL  
 211 05 05  
 212 99 PRT  
 213 58 FIX  
 214 00 00  
 215 43 RCL  
 216 06 06  
 217 99 PRT  
 218 43 RCL  
 219 07 07  
 220 99 PRT  
 221 22 INV  
 222 58 FIX  
 223 98 ADV  
 224 98 ADV  
 225 98 ADV  
 226 98 ADV  
 227 91 R/S



PRELIMINARY

COMPUTER PROGRAM - PART 2  
Binary Generator Economic Analysis  
ODOE Agreement #L50002

August 1983



## COMPUTER PROGRAM - PART 2

### BINARY GENERATOR ECONOMIC ANALYSIS

Oregon Department of Energy Agreement #L50002

#### INTRODUCTION

The Geo-Heat Center is currently under contract to the Oregon Department of Energy to assist in the evaluation of the operation of the binary generators located at Lakeview, Oregon. Task 2 of this contract is the development of a three part computer program related to the production of electricity using the Organic Rankine Cycle to convert the energy in low temperature geothermal water (approximately 180°F to 250°F). This report is concerned with Part 2 of Task 2, a generic type economic analysis based on the output from Part 1 and additional key parameters. Part 1, titled Computer Program - Part 1, Engineering Analysis of the Organic Rankine Cycle, was completed in July 1983. Part 3, an evaluation of the raffle cooling system performance, will be completed later.

#### METHODOLOGY

Part 2 utilizes the output from the Part 1 computer program. However, to simplify operation of this economic evaluation program, Part 1 calculations have been included. Thus, Part 2 does not require the use of the Part 1 computer program to calculate the nominal machine size and average net saleable power. An inflation multiplier (7% per annum past June 1983) is built into the program, and capital costs are adjusted. Capital costs for the binary generator and the cooling tower system are based on the calculated nominal machine size. Capital costs for geothermal piping, production well,

and injection well are based on geothermal water flow rate. Contingency and engineers fee (10%) is an added capital cost. Maintenance costs for the binary generator, cooling tower system, geothermal water piping and well pump maintenance are based on percentages of capital cost (including proration of the contingency and engineers fee). Respective percentages for the above are; 5%, 3%, 1% and 5%. No maintenance cost is applied to the wells. Taxes (1%) and insurance (1/2%), an operating cost, are based on total capital investment, excluding well costs. The program provides for public entities which do not pay property taxes. Purchased geothermal energy is treated as an operating cost, and is based on geothermal flow rates at the prices specified as an input. Annual electrical sales (\$/yr) are based on average net saleable power (kW) and 7,884 hours of operation per year. Annual gross income is the sum of electrical sales (\$/yr) and annual geothermal effluent sales (\$/yr). Effluent sale is based on geothermal water flow rate and price (\$/1000 gal) as specified as an input. Annual net income is gross income less total operating cost. Simple payback is total capital investment (\$) divided by annual net income (\$/yr). If desired, a more precise discounted cash flow economic analysis can be performed using output from this program. Such an analysis probably would include cost of capital, and where private investors are involved, income taxes, depreciation, depletion, energy credits and investment tax credits.

This program has considerable flexibility that will be demonstrated in the example problems that are included in this report. However, it should be remembered that this is a generic economic analysis, and may not produce as accurate an analysis as would a detailed site specific study.

COMPUTER INPUT AND OUTPUT  
Binary Generator Economic Analysis

Table 1

INPUT

STO 00 Property tax status (public 1, private 3).  
STO 01 Geothermal water temperature (°F).  
STO 02 Geothermal water flow rate (gpm).  
STO 03 Average annual wet bulb temperature (°F).  
STO 04 Static water level injection well (ft).  
STO 05 Pumping water level production well (ft).  
STO 09 Month of year (1 or 2 digits, dimensionless).  
STO 10 Year (last two digits, dimensionless).  
STO 11 Cost of purchased geothermal (\$/1000 gal).  
STO 12 Value of sold geothermal effluent (\$/1000 gal).

OUTPUT

RCL 06 Nominal machine size (kW).  
RCL 07 Average net saleable power (kW).  
RCL 08 Well pumping power (kW).  
RCL 13 Inflation multiplier, base June 1983 (dimensionless).  
RCL 14 Binary generator capital cost (\$).  
RCL 15 Cooling tower system capital cost (\$).  
RCL 16 Geothermal water piping capital cost (\$).  
RCL 17 Geothermal well pump capital cost (\$).  
RCL 18 Production well capital cost (\$).  
RCL 19 Injection well capital cost (\$).  
RCL 20 Contingency and engineers fee (\$).  
RCL 21 Total capital cost (\$).  
RCL 22 Binary generator maintenance (\$/yr).  
RCL 23 Cooling tower system maintenance (\$/yr).  
RCL 24 Geothermal water piping maintenance (\$/yr).  
RCL 25 Well pump maintenance (\$/yr).  
RCL 26 Total maintenance, 1st year (\$/yr).

OUTPUT cont'd.:

RCL 27 Taxes & insurance.

RCL 28 Annual cost of purchased geothermal (\$/yr).

RCL 29 Total operating cost, 1st year (\$/yr).

RCL 30 Net annual electricity sales (\$/yr).

RCL 31 Net annual geothermal effluent sales (\$/yr).

RCL 32 Simple capital payback before taxes (years).

## COMPUTER PROGRAM

This economic analysis has been programmed for use on a Texas Instrument TI-59 programmable calculator using a PC-100C printer. The program uses two sides of three magnetic cards. Table 1, titled Computer Input and Output, lists the ten items of required input data, and compatible input units. Also, shown are the twenty-three output items generated by the program.

An explanation of some of the input items is needed. The two digit number is the storage location for input, and recall location for output. Storage 00 (STO 00) is necessary so that property taxes are not included for tax free public entities. For public entities only insurance will be included and property taxes excluded as an operating cost. If the geothermal water is to be purchased, and the well cost and well pump cost are someone elses responsibility, enter 0 in STO 04 and STO 05. The program then excludes the pumping electricity for lift and injection, but does consider the electricity required to move the geothermal water through the above ground equipment. If the project owns a production well, but effluent discharge is to surface rather than to injection, enter 50% of the pumping level (STO 05) as the static water level in the injection well (STO 04). With this entry, the program excludes electricity for injection.

The program stops twice during the running of magnetic card #2. These stops are to permit review of the output data, and to delete or modify the output before the program proceeds. At the first stop, the calculated capital costs are printed out, and the maintenance costs at the second stop. As an example, at the first stop if geothermal is purchased, take out the

cost of the production well by entering 0 in STO 18. If the production well isn't owned by the project, the well pump probably isn't owned either. Enter 0 in STO 17. At the second stop, in reviewing the maintenance costs, make sure that these costs are consistent with the capital costs. In most cases, if the project doesn't own something, it won't pay the maintenance. Use of these program stops will become more understandable after studying the examples in this report and running a few problems.

### OPERATING THE PROGRAM

1. Turn on the calculator and the printer.
2. Enter both sides of Card #1. To do this, the display must be cleared (CLR) prior to and after card entry.
3. Enter the ten items of input ( in the proper units) in the correct storage positions as shown on Table 1. Don't forget the STO 00 entry.
4. Press RST, R/S. The program will run and terminate by printing ENTER CARD TWO.
5. Enter both sides of Card #2. Clear (CLR) display before entering side #2.
6. Press RST, R/S. Program will quickly print out CHECK CAPITAL and recall and print out RCL 14, RCL 15, RCL 16, RCL 17, RCL 18 and RCL 19. These are capital investment items that are identified on Table 1, respectively as; binary generator, cooling tower system, geothermal water piping, geothermal well pump, production well and injection well. Make any desired changes or deletions. For instance, if there is no injection well, enter 0 in STO 19.
7. Press R/S (do not press RST). Program will, in less than ten seconds, print out CHECK MAINTENANCE and recall and print out RCL 22, RCL 23, RCL 24 and RCL 25. These maintenance items are identified on Table 1, respectively as; binary generator, cooling tower system, geothermal water piping, and well pump. Make any desired changes or deletions by entering desired dollar figures in the appropriate storage.
8. Press R/S (do not press RST). Program, in less than ten seconds, will print out the simple payback as years to first decimal place. It then prints CARD THREE.

9. Enter both sides of Card #3. Clear (CLR) display before entering side #2.
10. The program will immediately recall and print out twenty-nine items from storage. The bottom line is the simple payback.

#### EXAMPLE PROBLEMS

To demonstrate operation of the program, particularly use of the stop feature, six example problems have been run and the results listed below. Each of the cases is based on 215°F geothermal water with a pumping lift of 200 feet, with a flow of 1200 gpm, and an average annual wet bulb temperature of 43°F.

Problem #1. Public ownership of total facilities, injection static water level at 80 feet, no sale of geothermal effluent.

Problem #2. Public ownership of all facilities, surface disposal of water, no sale of geothermal effluent.

Problem #3. Private ownership of all facilities, injection static water level 80 feet, sale of geothermal at \$.07/1000 gal.

Problem #4. Public ownership of all facilities except production well and well pump, purchase geothermal at \$.12/1000 gal, injection static water level at 80 feet, no sale of geothermal effluent. Pumping electricity paid by project.

Problem #5. Private ownership of all facilities except production well and well pump, purchase geothermal at \$.14/1000 gal, surface disposal of geothermal effluent, sale of geothermal effluent at \$.07/1000 gal, project pays for geothermal pumping electricity.

Problem #6. Private ownership of all facilities except production well and well pump, purchase geothermal at \$.14/1000 gal, surface disposal of geo-

thermal effluent, sale of geothermal effluent at \$.07/1000 gal, cost of geothermal pumping electricity included in geothermal purchase price.

# Problem #1

ENTER CARD TWO

CHECK CAPITAL

1438514. 14

319446. 15

61548. 16

78471. 17

121399. 18

91049. 19

CHECK MAINTENANCE

79118. 22

10542. 23

677. 24

4316. 25

10.8

CARD THREE

215. 01

1200. 02

43. 03

80. 04

200. 05

948. 06

580. 07

97. 08

0. 11

0. 12

1438514. 14

319446. 15

61548. 16

78471. 17

121399. 18

91049. 19

211043. 20

2321470. 21

79118. 22

10542. 23

677. 24

4316. 25

94653. 26

10439. 27

0. 28

105092. 29

320175. 30

0. 31

10.8

# Problem #2

ENTER CARD TWO

CHECK CAPITAL

1438514. 14

319446. 15

61548. 16

67684. 17

121399. 18

91049. 19

CHECK MAINTENANCE

79118. 22

10542. 23

677. 24

3723. 25

9.9

CARD THREE

215. 01

1200. 02

43. 03

100. 04

200. 05

948. 06

593. 07

84. 08

0. 11

0. 12

1438514. 14

319446. 15

61548. 16

67684. 17

121399. 18

0. 19

200859. 20

2209451. 21

79118. 22

10542. 23

677. 24

3723. 25

94060. 26

10380. 27

0. 28

104439. 29

327530. 30

0. 31

9.9

### Problem #3

ENTER CARD TWO  
CHECK CAPITAL

1438514.	14
319446.	15
61548.	16
78471.	17
121399.	18
91049.	19

CHECK MAINTENANCE

79118.	22
10542.	23
677.	24
4316.	25
9.9	

CARD THREE

215.	01
1200.	02
43.	03
80.	04
200.	05
948.	06
580.	07
97.	08
0.	11
0.07	12
1438514.	14
319446.	15
61548.	16
78471.	17
121399.	18
91049.	19
211043.	20
2321470.	21
79118.	22
10542.	23
677.	24
4316.	25
94653.	26
31317.	27
0.	28
125970.	29
320175.	30
39738.	31
9.9	

### Problem #4

ENTER CARD TWO  
CHECK CAPITAL

1438514.	14
319446.	15
61548.	16
78471.	17
121399.	18
91049.	19

CHECK MAINTENANCE

79118.	22
10542.	23
677.	24
0.	25
13.9	

CARD THREE

215.	01
1200.	02
43.	03
80.	04
200.	05
948.	06
580.	07
97.	08
0.12	11
0.	12
1438514.	14
319446.	15
61548.	16
0.	17
0.	18
91049.	19
191056.	20
2101614.	21
79118.	22
10542.	23
677.	24
0.	25
90337.	26
10007.	27
68122.	28
168466.	29
320175.	30
0.	31
13.9	

# Problem #5

ENTER CARD TWO  
CHECK CAPITAL

1438514.	14
319446.	15
61548.	16
67684.	17
121399.	18
91049.	19

CHECK MAINTENANCE

79118.	22
10542.	23
677.	24
0.	25

12.0

CARD THREE

215.	01
1200.	02
43.	03
100.	04
200.	05
948.	06
593.	07
84.	08
0.14	11
0.07	12
1438514.	14
319446.	15
61548.	16
0.	17
0.	18
0.	19
181951.	20
2001459.	21
79118.	22
10542.	23
677.	24
0.	25
90337.	26
30022.	27
79476.	28
199835.	29
327530.	30
39738.	31
12.0	

# Problem #6

ENTER CARD TWO  
CHECK CAPITAL

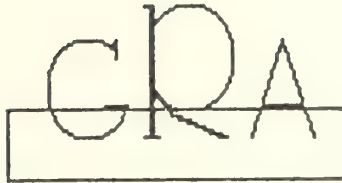
1438514.	14
319446.	15
61548.	16
13753.	17
121399.	18
91049.	19

CHECK MAINTENANCE

79118.	22
10542.	23
677.	24
0.	25
9.8	

CARD THREE

215.	01
1200.	02
43.	03
0.	04
0.	05
948.	06
660.	07
17.	08
0.14	11
0.07	12
1438514.	14
319446.	15
61548.	16
0.	17
0.	18
0.	19
181951.	20
2001459.	21
79118.	22
10542.	23
677.	24
0.	25
90337.	26
30022.	27
79476.	28
199835.	29
364306.	30
39738.	31
9.8	



REVISED BINARY GENERATOR ECONOMIC ANALYSIS

For the Oregon Department of Energy  
(Under Agreement #150002 with Oregon Institute of Technology)

By  
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December 19, 1984



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# REVISED BINARY GENERATOR ECONOMIC ANALYSIS

## I INTRODUCTION

In 1983 a report was prepared for the Oregon Department of Energy by the Geo-Heat Center, Oregon Institute of Technology, titled Computer Program Part 2, Binary Generator Economic Analysis. The author of the report, Gene P. Ryan, prepared this revised report through a subcontract to the Geo-Heat Center.

The original report developed a computer method of evaluating binary generator applications. Using geothermal water flow rate and temperature, well pumping water level, injection well water level, wet bulb temperature, value of electricity, and value of geothermal effluent and/or purchased geothermal the program computes the size of the binary generator, well pumping power, net saleable power, capital costs, operating costs, and simple capital payback. The computer method was based on using R114 as the refrigerant, and was limited to a minimum wet bulb temperature of 40°F. Also, the intended use of the program was for geothermal temperatures of 250°F, or less.

The purpose of the study reported here is to revise the computer program to permit its use to a minimum wet bulb temperature of 30°F, and a geothermal water temperature up to 300°F.

The original program was first written for use on the Texas Instrument TI-59 hand held computer. It was then produced in spreadsheet format using Visicalc (TM VisiCorp) and an Apple III computer. The program developed here is in the Perfect Calc (TM Perfect Software) form, and can be readily adapted to other spreadsheet programs.

## II METHODOLOGY

An existing proprietary R114 binary power generating cycle computer program written in S-Basic (TM Digital Research) was revised to accommodate 30°F wet bulb temperatures and the 300°F geothermal water temperatures. Output from this program was checked against runs used to develop the original ODOE program at the intermediate wet bulb temperatures and at various geothermal flow rates and temperatures. No consequential differences were found.

The refrigerants R114 and isobutane were then compared at higher evaporator temperatures. This was done using a proprietary side by side comparison written using Perfect Calc. The difference in calculated net power outputs was less than 100 kW at a 220°F evaporator temperature. It was also determined, based on runs using isobutane as the refrigerant that there was a trend toward higher net power output at lower evaporator temperatures. All of this confirmed the suitability of R114 as the refrigerant of choice.

Finally, additional runs were made using the S-Basic program to develop the formulas to modify the ODOE binary generator economic analysis program.

### III APPLICATION

Enclosed as part of this report is a computer listing for the modified program. The cells that contain changed formulas are g21, d22, g26, and d27. Though the cell numbers do not correspond to the VisiCalc numbers the location can readily be identified by either the related title or place of use. For cell d27 the "int(.5+(.001" is to make Perfect Calc round. This may not be required for other spread sheet programs. The "int" function is also used in other cost formula cells. Also, the superscript "2" means 'raise to a power'.

### IV CONCLUSION

Whereas the first program was limited to a minimum ambient wet bulb temperature of 40°F the revised program accomodates wet bulb temperatures as low as 30°F. Also, the revised program is suitable for evaluating binary power generation applications using geothermal water up to 300°F in temperature.

There are many practical consideration involved in selecting a refrigerant for binary power generation. However, a discussion of the selection process is beyond the scope of this report. Readers wishing additional information may find the paper titled Binary Generator Refrigerants - Picking the Right Stuff to be useful. The paper was published in the 1984 Geothermal Resources Council Transactions, or is available from the author of this report.

APPENDIX A  
REVISED BINARY GENERATOR ECONOMIC ANALYSIS  
PROGRAM LISTING

```

>a1:±wc3
>a1:±jcr
>b1:" BINARY GENERATOR ECONOMIC ANALYSIS
>b1:±wc49
>c1:±wc4
>e1:±wc10
>b2:" GENE RYAN & ASSOCIATES
>b3:"
>b4:"INPUT
>a5:"1
>b5:" PRODUCTION WELL (YES, enter 1; NO, enter 0)
>d5:1.0000000000000000E+00
>a5:±d136
>a6:"2
>b6:" INJECTION WELL (YES, enter 1; NO, enter 0)
>d6:1.0000000000000000E+00
>a6:±d136
>a7:"3
>b7:" PROPERTY TAXES (PUBLIC,enter 1; PRIVATE,enter3)
>d7:3.0000000000000000E+00
>a7:±d136
>a8:"4
>b8:" GEOTHERMAL WATER TEMPERATURE
>d8:2.1500000000000000E+02
>e8:" degree F
>a8:±d136
>a9:"5
>b9:" GEOTHERMAL WATER FLOW RATE
>d9:1.2000000000000000E+03
>e9:" gpm
>a9:±d136
>a10:"6
>b10:" AVERAGE ANNUAL WET BULB TEMPERATURE
>d10:3.0000000000000000E+01
>e10:" degree F
>a10:±d136
>a11:"7
>b11:" STATIC WATER LEVEL IN INJECTION WELL
>d11:8.0000000000000000E+01
>e11:" feet
>a11:±d136
>a12:"8
>b12:" PUMPING WATER LEVEL IN PRODUCTION WELL
>d12:2.0000000000000000E+02
>e12:" feet
>a12:±d136
>a13:"9
>b13:" MONTH OF THE YEAR (1 or 2 digits)
>d13:8.0000000000000000E+00
>e13:" month
>a13:±d136
>a14:"10
>b14:" YEAR (last 2 digits)
>d14:8.3000000000000000E+01

```

```

>e14:" year
>a14:±d136
>a15:"11
>b15:" PURCHASED GEOTHERMAL (unit cost or 0)
>d15:0
>e15:" $/1000gal
>a15:±d14
>a16:"12
>b16:" GEOTHERMAL EFFLUENT SOLD (unit cost or 0)
>d16:7.000000000100E-02
>e16:" $/1000gal
>a16:±d14
>a17:"13
>b17:" UNIT VALUE OF ELECTRICITY SOLD
>d17:7.000000000350E-02
>e17:" $/kWh
>a17:±d14
>g20:=d8-172
>b21:"OUTPUT
>g21:=d10-29.99
>a22:"14
>b22:" NOMINAL MACHINE SIZE
>d22:=(2.088-(.032*g21))*d9*(d8-172)/128*1.4
>e22:" kW
>g22:=8640*d9/((.0000015774*(d8^2.075)+2.301)*7.481)
>a22:±d10
>a23:"15
>b23:" WELL PUMPING POWER
>d23:=(d12+(abs(d12-2*d11)*d6)+51)*g22/1725895
>e23:" kW
>a23:±d10
>a24:"16
>b24:" AVERAGE NET SALEABLE POWER
>d24:=d22/1.4-d23
>e24:" kW
>a24:±d10
>a25:"17
>b25:" INFLATION MULTIPLIER (base, June 1983)
>d25:=((d14-83)*12+d13-6)*.00583)+1
>a25:±d13
>a26:"18
>b26:" BINARY GENERATOR CAPITAL COST
>c26:" $
>d26:=1000*int(.5+(.001*(1800-(d8-180)*8.5714)*d22*d25))
>g26:=d10-29.99
>C26:" $
>a26:±d10
>a27:"19
>b27:" COOLING TOWER SYSTEM CAPITAL COST
>c27:" $
>d27:=1000*int(.5+(.001*((g26*.568)+33.97)*8.33*d22*d25))
>g27:=d9-300
>C27:" $
>a27:±d136

```

```

>a28:"20
>b28:" GEOTHERMAL WATER PIPING CAPITAL COST
>c28:" $
>d28:=1000*int(.5+(.001*(g27*83.286-(g27^1.1129*27.898)+40000*d25)))
>c28:" $
>a28:±d136
>a29:"21
>b29:" GEOTHERMAL WELL PUMP CAPITAL COST
>c29:" $
>d29:=1000*int(.5+(.001*(d23*800*d25*d5)))
>c29:" $
>a29:±d136
>a30:"22
>b30:" PRODUCTION WELL CAPITAL COST
>c30:" $
>d30:=1000*int(.5+(.001*(d9*100*d25*d5)))
>c30:" $
>a30:±d136
>a31:"23
>b31:" INJECTION WELL CAPITAL COST
>c31:" $
>d31:=1000*int(.5+(.001*(d25*d6*d9*100*.75)))
>c31:" $
>a31:±d136
>a32:"24
>b32:" CONTINGENCY AND ENGINEERS FEE
>c32:" $
>d32:=1000*int(.5+(.001*((d26+d27+d28+d29+d30+d31)*.1)))
>c32:" $
>a32:±d136
>a33:"25
>b33:" TOTAL CAPITAL COST
>c33:" $
>d33:=d26+d27+d28+d29+d30+d31+d32
>c33:" $
>a33:±d10
>a34:"26
>b34:" BINARY GENERATOR MAINTENANCE
>c34:"$/yr
>d34:=1000*int(.5+(.001*(d26*.055)))
>c34:"$/yr
>a34:±d136
>a35:"27
>b35:" COOLING TOWER SYSTEM MAINTENANCE
>c35:"$/yr
>d35:=1000*int(.5+(.001*(d27*.033)))
>c35:"$/yr
>a35:±d136
>a36:"28
>b36:" GEOTHERMAL WATER PIPING MAINTENANCE
>c36:"$/yr
>d36:=1000*int(.5+(.001*(d28*.011)))
>c36:"$/yr
>a36:±d136

```

```

>a37:"29
>b37:" WELL PUMP MAINTENANCE
>c37:"$/yr
>d37:=1000*int(.5+(.001*(d29*.055)))
>C37:"$/yr
>a37:±d136
>a38:"30
>b38:" TOTAL MAINTENANCE
>c38:"$/yr
>d38:=d34+d35+d36+d37
>C38:"$/yr
>a38:±d136
>a39:"31
>b39:" TAXES AND INSURANCE
>c39:"$/yr
>d39:=1000*int(.5+(.001*((d33-((d30+d31)*1.1))*0.005*d7)))
>C39:"$/yr
>a39:±d136
>a40:"32
>b40:" ANNUAL COST OF PURCHASED GEOTHERMAL
>c40:"$/yr
>d40:=1000*int(.5+(.001*((d9*d15*8760)/1000*60*.9)))
>C40:"$/yr
>a40:±d136
>a41:"33
>b41:" TOTAL OPERATING COST, 1st year
>c41:"$/yr
>d41:=d38+d39+d40
>C41:"$/yr
>a41:±d136
>a42:"34
>b42:" NET ANNUAL ELECTRICITY SALES
>c42:"$/yr
>d42:=1000*int(.5+(.001*(d24*d17*8760*.9)))
>C42:"$/yr
>a42:±d136
>a43:"35
>b43:" NET ANNUAL GEOTHERMAL EFFLUENT SALES
>c43:"$/yr
>d43:=1000*int(.5+(.001*((d9*d16*8760*60)/1000*.9)))
>C43:"$/yr
>a43:±d136
>a44:"36
>b44:" SIMPLE CAPITAL PAYBACK, before taxes
>d44:=(d33/(d42+d43-d41))
>e44:" years
>a44:±d11

```





## APPENDIX 7

### HEATPLAN Program

- o Summary
- o HEATPLAN User Manual



## SUMMARY

### HEATPLAN Computer Analysis

HEATPLAN 2.0 is a microcomputer program designed to provide a neighborhood-level inventory of heat demands by type of land-use, and a preliminary assessment of district heating favorabilities for the neighborhoods. It is intended for use by local officials for purposes of 1) establishing a basis for heat supplies and demands as determinants in the community development process, and 2) identifying areas in communities where detailed engineering and economic assessments of current district heating opportunities may be warranted.

HEATPLAN evaluates a community according to the heat demands of its land-uses; the heat supplies that geothermal, biomass, or waste heat can offer; and the resulting favorability for district heating on the basis of heat demand per unit of land area, and the cost-effectiveness of serving such demand through a district system. The program estimates the minimum heat price and minimum heat sales per unit of land area necessary for successfully operating a community-wide system. It then compares each neighborhood's heat demands with the necessary community-wide minimum, and the resulting heat density ratio constitutes a favorability rating for each neighborhood, indicating either its suitability for district heating, or the need for appropriate land-use changes, e.g. increased development densities.

Heat prices for direct utilization sites examined by the Assessment Team are shown in the following tables. Prices estimated range from \$1.10 to \$765 per million Btu of heat.

Full price evaluation data generated by HEATPLAN is provided in subsequent tables.



# DIRECT USE SITE EVALUATIONS FOR IDAHO

SITE NAME	POPULATION	BPA CUST	DEGREE DAYS	ENERGY MW	OFFSET MW	PHASE I	PHASE II	PHASE III	TOTAL EXPLR	TEMP F	WELL COST	TOTAL DISTR	TOTAL TRANS	TOTAL SYSTEM	O&M COST	SALE PRICE
AMERICAN FALLS	3626	N	6902	4	0.32	0	82500	37750	120250	77	198750	157505	30347	444592	28786	9.16
AMMON	4669	N	7888	<1	0.38	5000	82500	237750	325250	68	648125	162949	408210	1402229	69132	21.59
ASHTON	1219	N	8793	31	0.15	0	70000	37750	107750	106	438125	137516	204194	935802	38946	33.13
BOISE	102451	N	5833	100	8.97	0	30500	3750	34250	170	292500	1029269	31628	1556407	118381	1.25
BUHL	3629	N	6146	48	0.24	0	70000	37750	107750	90	945312	157190	25118	562561	9888	9.18
BUTTE CITY	93	N	8184	15	0.00	0	82500	37750	120250	99	214500	124712	35410	430815	60006	583.57
CALDWELL	17699	N	5736	35	1.28	0	30500	37750	68250	120	562187	234651	29115	949742	33266	3.77
CASCADE	945	N	8720	25	0.11	41000	40500	237750	319250	108	328859	135400	2585	587934	13204	21.58
CHALLIS	758	Y	7761	13	0.10	41000	70000	37750	148750	104	740625	134222	25923	1035885	13669	37.99
CHUBBUCK	7052	N	7063	2	0.56	0	60000	37750	97750	95	159062	177739	35647	428315	46684	6.93
COUNCIL	917	N	6610	1	0.09	0	73500	37750	111250	72	129687	134975	25519	348218	12564	17.67
EAGLE	2620	N	5833	5	0.14	0	73500	37750	111250	104	169063	140822	35467	397154	42672	25.22
EMMETT	4605	N	5623	<1	0.33	0	70000	237750	307750	77	321812	162318	30355	617382	29017	10.39
FAIRFIELD	404	N	8830	6	0.05	5000	70000	37750	112750	70	257636	129982	30580	480971	27343	55.84
FILER	1645	N	6146	5	0.09	0	70000	37750	107750	89	346250	139891	25053	587873	10524	24.78
GARDEN CITY	4568	N	5833	10	0.44	0	62500	37750	107750	116	428125	166177	44603	791704	10635	1.89
GLENN'S FERRY	1374	N	5469	46	0.12	5000	70000	37750	112750	100	287187	138730	26969	520820	17102	21.07
GRAND VIEW	366	N	5507	123	0.02	0	44000	37750	81750	185	818281	134179	97960	1207983	19554	185.62
HAILEY	2109	N	8184	28	0.19	5000	38000	237750	280750	138	280000	152921	226347	759413	17738	17.55
HANSEN	1078	N	5717	<1	0.05	0	90750	37750	128500	68	200875	136412	32832	425637	34186	54.21
HOMEDALE	2078	N	5736	<1	0.13	0	90750	37750	128500	73	228438	142888	48677	483012	82153	45.67
IDAHO CITY	300	N	7643	19	0.02	5000	82500	237750	325250	108	320000	128577	28488	548625	20901	106.47
IDAHO FALLS	39590	N	7888	<1	3.23	5000	82500	237750	325250	68	648125	134159	1154838	2466201	123292	1.65
KETCHUM	2200	N	8184	30	0.31	5000	38000	237750	280750	160	280000	182345	42470	580537	65152	17.45
KIMBERLY	2307	N	6164	<1	0.14	0	90750	37750	128500	84	307187	144012	32870	556679	34995	24.96
KUNA	1767	N	5949	17	0.12	0	73500	37750	111250	77	169063	141208	35461	397590	42569	27.82
LAVA HOT SPRINGS	467	N	7063	14	0.05	5000	70000	237750	312750	113	310000	131188	73729	592134	36271	72.19
MALAD CITY	1915	N	7061	4	0.17	5000	70000	37750	112750	77	438125	152908	117241	849928	38468	28.25
MELBA	276	N	5736	18	0.01	5000	73500	37750	116250	75	223359	128546	35414	445417	41549	196.37
MERIDIAN	6658	N	5833	<1	0.77	0	73500	37750	111250	77	169062	175587	35595	437280	45624	8.76
MIDVALE	205	N	6809	14	0.03	36000	73500	37750	147250	83	312422	127070	32823	543162	33913	95.33
MOUNTAIN HOME	7540	N	5979	<1	0.68	0	70000	37750	107750	68	257656	180757	111973	632943	242132	22.90
MOUNTAIN HOME AFB	9975	N	5979	<1	1.36	0	33000	37750	70750	68	143828	207162	155532	582501	411232	18.36
NAMPA	25112	N	5736	30	2.17	0	38000	37750	75750	120	572188	260381	29407	991271	46129	2.50
PARMA	1820	N	5736	<1	0.13	0	73500	37750	111250	81	169062	141229	29740	425351	40797	1.78
PAUL	940	N	6867	1	0.08	5000	90750	237750	333500	72	400875	134508	32845	653462	28195	40.91
PAYETTE	5448	N	5717	<1	0.39	0	90750	37750	128500	68	179218	170226	30899	437395	31189	7.65
POCATELLO	46274	N	7063	3	4.00	0	30500	37750	68250	95	129062	363320	37121	608928	8332	1.60
PRESTON	3759	N	7325	4	0.32	0	70000	37750	107750	180	438125	192034	30348	759583	39937	14.28
REXBURG	11559	N	8311	6	1.06	7000	40500	37750	85250	79	124296	226602	35863	448226	76168	5.25
SODA SPRINGS	4051	N	7063	5	0.41	0	38000	37750	75750	88	408125	164036	26055	687948	8332	7.88
STANLEY	99	Y	7761	12	0.00	48000	73500	237750	359250	105	688125	124938	26919	1007978	15768	765.26
TWIN FALLS	26209	N	6146	7	1.84	5000	70000	37750	112750	99	503750	261086	25804	909235	10056	1.81
WEISER	4771	N	5839	<1	0.38	36000	40500	237750	314250	70	342484	163374	25773	644412	31717	9.86



D I R E C T   U S E   S I T E   E V A L U A T I O N S   F O R   M O N T A N A

SITE NAME	POPUL ATION	BPA CUST	DEGREE DAYS	ENERGY MM	OFFSET MM	PHASE I	PHASE II	PHASE III	TOTAL EXPLR	TEMP F	WELL COST	TOTAL DISTR	TOTAL TRANS	TOTAL SYSTEM	O&M COST	SALE PRICE
ALHAMBRA - CLANCY	230	N	8129	27	0.02	72500	60250	237750	370500	133	370000	130821	140815	796963	26494	157.96
ANACONDA	9771	Y	8407	9	0.93	72500	90750	237750	401000	72	728125	183900	25758	1125340	19554	4.99
AVON	220	Y	8129	4	0.02	72500	90750	237750	401000	79	400000	127372	66967	713206	15031	129.92
BAKERS HOLE-W. YELLOWSTONE	756	N	10897	<1	0.07	72500	90750	237750	401000	61	400000	133725	72256	696878	15687	38.77
BEAR CREEK - GARDINER	600	N	7520	4	0.06	62250	90750	237750	390750	72	360000	132204	118715	733102	26573	60.52
BEDFORD - TOWNSEND	1371	N	8227	3	0.13	43000	90750	237750	371500	75	370000	139599	862407	1645208	417015	207.91
BOZEMAN HOT SPRINGS	18670	N	8407	24	1.84	43000	40500	203750	287250	129	424121	364750	1914975	3109424	319945	15.17
BRIDGER CANYON - BOZEMAN	18670	N	8165	24	1.84	43000	61250	237750	342000	70	586994	250978	371700	1450527	102424	5.61
CANAS HOT SPRINGS	20	Y	7020	28	0.07	43000	60250	237750	341000	124	355750	124301	49738	609257	18392	41.45
CAMPAGUA HOT SPRINGS	675	Y	7020	17	0.07	12000	30750	3750	46500	129	92525	126049	78632	341786	163427	146.40
CARTERS BRIDGE-LIVINGSTON	6883	N	7281	6	0.66	43000	61250	237750	342000	82	340000	172898	1278475	2149648	466684	50.07
CHICO - LIVINGSTON	15	N	7281	16	0.66	43000	90750	237750	371500	115	370000	172922	1726582	2723405	238724	33.35
CORNIN - GARDINER	600	N	7530	23	0.06	43000	61250	237750	342000	149	504062	137455	381435	1227542	71353	134.43
DEER LODGE	4306	Y	8407	8	0.81	62250	90750	237750	390750	77	390000	178882	303141	1046428	47457	7.35
ELKHORN - POLARIS	20	N	10824	18	0.00	62250	90750	237750	390750	119	360000	122297	279030	913592	53714	2562.75
GALLOGLY - SULA	44	Y	8550	14	0.00	72500	90750	237750	401000	120	400000	123308	880238	1684256	136654	2576.08
GARRISON	150	Y	8129	5	0.01	72500	90750	237750	401000	76	400000	126082	242169	921901	39937	315.29
GREYSON - TOWNSEND	1371	N	8227	<1	0.13	62250	90750	237750	390750	64	360000	139599	842417	1609220	335051	173.53
LOLO	10	Y	7931	18	0.15	72500	90750	237750	401000	115	400000	139599	1643200	2619242	350181	185.22
MEDICINE HOT SPRINGS	44	Y	8550	26	0.00	43000	90750	237750	371500	113	370000	123308	228226	865840	45061	1033.29
PIPESTONE - WHITEHALL	1035	N	8200	29	0.10	72500	90750	237750	401000	135	400000	142985	341240	1061070	51355	58.76
QUINNS - PARADISE	250	Y	8000	20	0.02	72500	90750	237750	401000	77	400000	127884	25024	635844	10529	95.33
RENOVA - WHITEHALL	1035	N	8200	17	0.10	43000	71250	237750	352000	122	350000	142997	344110	1004528	43755	52.90
SLEEPING CHILD - HAMILTON	81	Y	8550	27	0.25	72500	90750	237750	401000	126	400000	158237	2063923	3146593	551800	164.67
TOSTON	100	N	8200	<1	0.01	43000	61250	237750	342000	59	340000	124958	973119	1725693	431019	2732.80
WENOT WELL - OPPORTUNITY	9771	N	8414	<1	0.06	62250	90750	237750	390750	75	360000	132201	25038	594824	10835	39.48
WHITE SULFUR SPRINGS	1200	N	8792	24	0.12	43000	82500	237750	363250	113	517500	137387	31993	789912	31097	34.40



DIRECT USE SITE EVALUATIONS FOR OREGON

SITE NAME	POPUL ATION	BPA CUST	DEGREE DAYS	ENERGY MW	OFFSET MW	PHASE I	PHASE II	PHASE III	TOTAL EXPLR	TEMP F	WELL COST	TOTAL DISTR	TOTAL TRANS	TOTAL SYSTEM	O&M COST	SALE PRICE
ADRIAN AREA	175	N	5534	15	0.01	0	61250	237750	299000	135	515468	127652	27164	804342	14507	249.71
ARLINGTON	465	Y	4821	1	0.04	44500	90750	237750	373000	72	479375	128701	34913	771587	34653	109.04
ASHLAND	15180	Y	5143	25	1.25	36000	42000	237750	315750	111	563688	217045	29196	825330	26316	3.23
ATHENA AREA	955	Y	5240	<1	0.08	44500	90750	237750	373000	70	657656	132582	62236	1072969	101407	112.25
BAKER	9690	N	6909	16	0.85	36000	61250	237750	335000	126	2472812	183229	109036	3318094	54251	16.33
BOARDMAN AREA	1190	Y	5744	2	0.10	44500	90750	237750	373000	79	513500	134112	71762	863249	98359	81.58
BURNS AREA	4350	N	7212	41	0.33	0	57750	237750	295500	140	461438	178329	969813	1851017	138835	41.11
COVE AREA	475	N	6069	5	0.03	36000	61250	237750	335000	113	2489219	128835	32948	3181202	31317	327.12
ECHO AREA	610	Y	5240	1	0.05	56500	90750	237750	385000	72	549375	129972	37494	884209	41004	100.59
GOVERNMENT CAMP	550	Y	7949	25	0.04	0	30500	37750	68250	70	247187	129568	134523	587971	49091	94.82
HAINES	355	N	6909	21	0.03	36000	90750	237750	364500	149	575250	130841	224529	1116744	35733	173.19
HEPPNER AREA	1385	Y	5744	<1	0.11	56500	90750	237750	385000	70	533500	135220	30989	839651	26583	36.02
HERMISTON	9630	Y	5123	<1	0.56	44500	90750	237750	373000	70	370000	181719	37924	838822	45622	1.53
HUNTINGTON AREA	550	N	6906	3	0.04	36000	61250	237750	335000	75	483500	129539	35840	778654	24030	94.54
IMBLER	290	N	6069	102	0.02	36000	61250	237750	335000	154	340000	129785	1091414	2260889	82111	555.12
IRRIGON AREA	870	Y	5744	<1	0.07	44500	90750	237750	373000	68	531437	132030	28254	830065	16744	49.18
JORDAN VALLEY	460	N	5534	13	0.02	44250	61250	237750	343250	122	2472812	132421	30224	2478012	11170	375.24
KANNEETA HOT SPRINGS AREA	100	Y	6441	13	0.08	48000	90750	237750	376500	126	676750	125934	37040	1031669	14608	46.50
KLAMATH FALLS AREA	17100	N	6516	48	1.53	0	0	0	0	219	38587	332761	297691	769395	68373	4.02
LAGRANDE AREA	11920	N	6377	32	1.00	36000	61250	237750	335000	232	662875	240132	29518	1119030	29506	5.19
LAKEVIEW AREA	2810	N	7069	68	0.26	0	79000	237750	316750	204	481437	177289	43899	808020	58248	21.79
LEXINGTON AREA	290	Y	5744	<1	0.02	56500	90750	237750	385000	68	533500	126848	39478	839791	48009	200.50
MILTON FREEWATER AREA	5145	Y	4811	<1	0.33	44500	90750	237750	373000	68	612156	165773	85338	1035921	62145	20.13
NORTH POWDER	440	N	6909	11	0.04	36000	90750	237750	364500	109	3711563	128554	42468	3196602	12086	279.28
OAKRIDGE AREA	3560	Y	6026	4	0.29	0	79000	237750	316750	84	3138750	157163	25449	1033634	12914	13.50
ONTARIO AREA	9125	N	5707	2	0.65	0	90750	237750	328500	77	599063	180522	35175	977710	33360	7.65
PAISLEY AREA	345	Y	6377	40	0.02	36000	90750	237750	364500	232	360000	130823	223259	1006848	68621	10.72
PARKDALE	UNINC	Y	5567	32	0.02	0	88250	237750	326000	206	366094	130077	26871	627651	15035	94.92
PENDLETON AREA	14550	N	5240	<1	1.22	44500	90750	237750	373000	68	549375	223441	61982	1001758	108795	7.62
PILOT ROCK AREA	1640	Y	5240	<1	0.13	44500	90750	237750	373000	68	571796	136615	95009	964105	181531	96.07
RAJNEESHPURAM	1500	Y	6441	<1	0.05	44500	90750	237750	373000	68	513500	129982	26457	803927	14339	62.22
RIITTER HOT SPRINGS	40	Y	6753	21	0.02	36000	90750	237750	364500	154	360000	123365	26021	3170638	13381	418.57
SPRAY	125	Y	5744	6	0.01	49500	90750	237750	378000	91	595250	124530	27363	896572	17192	355.36
STANFIELD AREA	1620	Y	5240	1	0.09	44500	90750	237750	373000	72	585250	136346	42279	916650	52939	64.85
THE DALLES	11260	N	4402	<1	0.94	36000	90750	237750	364500	68	2333125	188361	31114	996720	29015	5.05
TRUTDALE	6545	Y	4792	12	0.34	36000	90750	237750	364500	167	2492812	207228	635920	4003152	42781	45.02
UMATILLA AREA	2990	N	5123	1	0.27	44500	90750	237750	373000	72	585250	154037	61733	961224	101487	32.25
UNION AREA	2065	N	6069	14	0.16	36000	61250	237750	335000	176	555250	146608	49795	901984	76318	43.27
VALE HIGH SCHOOL AREA	1560	N	5879	1	0.48	0	11500	237750	249250	220	429375	163633	131493	833176	20880	7.83
WESTON AREA	705	Y	5240	<1	0.06	44500	90750	237750	373000	70	657000	130752	61912	1019597	100496	145.40



DIRECT USE SITE EVALUATIONS FOR WASHINGTON

SITE NAME	POPULATION	BPA CUST	DEGREE DAYS	ENERGY MM	OFFSET HW	PHASE I	PHASE II	PHASE III	TOTAL EXPLR	TEMP F	WELL COST	TOTAL DISTR	TOTAL TRANS	TOTAL SYSTEM	OMM COST	SALE PRICE
BENTON CITY	1900	Y	5245	1	0.11	0	49750	237750	287500	80	484444	141679	149011	930169	277154	166.19
CHENEY	7600	Y	6606	4	5.56	0	52250	37750	90000	75	440000	266951	115316	945607	308792	3.67
CLARKSTON	6700	N	5470	1	0.63	0	81750	37750	119500	78	338750	172098	82453	682296	215851	22.76
COLFAX	2820	N	6311	2	0.58	5000	52250	237750	295000	70	397222	187943	76531	794035	50341	9.02
COLLEGE PLACE	5675	N	5040	27	1.42	0	52250	37750	90000	75	284444	215331	66160	679123	176053	8.49
CONNELL	1840	Y	6013	35	1.07	0	49750	37750	87500	77	284444	120853	146750	789854	117184	8.22
DAVENPORT	1580	N	7048	3	0.09	0	81750	237750	319500	76	757500	137775	107952	1206272	299778	211.34
EAST WENATCHEE	1605	Y	5839	<1	0.67	0	58750	37750	96500	96	586111	203688	125103	1097882	54163	9.56
ELLENGRUB	11500	Y	6542	1	10.55	0	49750	37750	87500	64	247500	431297	87602	919678	183577	1.22
EPHRATA	5440	Y	5500	26	0.40	0	49750	37750	87500	84	245556	166208	67414	575013	79448	15.35
GRANDVIEW	6300	N	5366	1	3.99	5000	52250	37750	95000	72	284722	474429	148022	1088608	181948	3.24
GRANGER	1810	N	5366	<1	0.12	5000	52250	37750	95000	70	137643	140468	25067	363812	11736	13.28
HARRAH	345	N	5182	2	0.02	5000	52250	37750	95000	90	294445	129207	30219	544644	29750	138.68
KENNEWICK	29810	Y	4947	1	3.81	0	49750	237750	287500	85	445555	466234	134070	1202739	127819	2.80
LIND	594	N	6013	1	0.05	0	49750	37750	87500	70	265000	132066	123785	598979	354410	411.14
MABTON	1235	N	5366	1	0.08	5000	52250	37750	95000	75	275000	137469	103010	618575	298928	214.17
HOGES LAKE	10300	Y	6398	60	0.82	0	49750	37750	87500	75	230000	179860	64346	569047	76400	7.29
NORTH BONNEVILLE	427	Y	5335	7	0.02	0	52250	237750	290000	69	145000	130143	55776	397103	74352	182.63
ODESSA	1020	N	6178	40	0.08	0	52250	37750	87500	69	445556	136569	70786	783493	170354	137.50
OTHELLO	4570	N	5819	87	3.62	0	49750	37750	87500	69	245555	392959	133318	887659	146368	2.91
PASCO	19100	Y	4947	<1	1.27	0	19250	37750	57000	85	215555	242943	129871	706044	151100	8.40
POMEROY	1675	N	5747	1	0.14	0	81750	37750	119500	73	277500	140597	60448	574254	142409	68.17
PROSSER	3788	Y	5181	2	2.82	0	49750	37750	87500	77	284444	299477	86274	804234	65216	2.11
PULLMAN	23200	N	6775	2	28.74	5000	52250	237750	295000	70	387500	579440	87626	1265479	501466	1.10
RICHLAND	33550	Y	5346	<1	3.01	0	19250	37750	57000	85	280000	3180700	308340	4334396	956804	17.63
RITTVILLE	1860	N	6212	<1	0.16	0	49750	237750	287500	70	412500	152593	103618	796018	285323	116.06
SOAP LAKE	1240	Y	6398	3	0.10	0	58750	237750	296500	75	455556	137616	62088	786312	69577	59.79
ST MARTINS HOT SPR RESORT	30	Y	5335	9	0.01	0	49750	237750	287500	127	395000	127151	37489	675313	36308	387.42
STEVENSON	1160	Y	5335	6	0.06	0	49750	237750	287500	93	421250	136874	25734	706629	12247	41.16
SUNNYSIDE	9450	N	5366	<1	2.88	5000	52250	37750	95000	75	259075	308942	32551	720141	61487	1.91
TOPPENISH	6575	N	5182	<1	1.00	5000	52250	37750	95000	72	257500	2361932	267543	630051	31106	3.57
WAKIACUS	UNINC	Y	6219	4	0.00	0	79250	237750	317000	81	355000	127140	26195	610062	13658	329.20
WALLA WALLA	25600	N	5040	30	6.15	0	52250	37750	90000	78	284444	570588	78921	1120744	181294	2.08
WARDEN	1463	N	5819	1	2.48	0	58750	37750	96500	71	275000	297161	91374	796242	50278	2.07
WASHTUCNA	280	Y	6013	2	0.02	0	49750	237750	287500	74	406667	128342	57245	681092	122658	377.27
WENATCHEE	17150	Y	5839	<1	2.57	0	58750	37750	96500	96	586111	384065	126926	1196522	127335	4.34
WEST RICHLAND	2641	Y	5346	<1	0.17	0	19250	37750	57000	80	235000	151650	142029	607980	262567	94.95
YAKIMA	48500	N	5941	62	6.21	5000	52250	37750	95000	74	226787	520281	42616	947622	141859	1.68
ZILLAH	1685	N	5182	3	1.00	5000	52250	37750	95000	78	267344	211816	98212	692846	80278	6.52

# DIRECT UTILIZATION SITE ECONOMIC RANKING: IDAHO

SITE	\$/MILLION BTU
1. Boise	1.25
2. Pocatello	1.60
3. Idaho Falls	1.65
4. Parma	1.78
5. Twin Falls	1.81
6. Garden City	1.89
7. Nampa	2.50
8. Caldwell	3.77
9. Rexburg	5.25
10. Chubbuck	6.93
11. Payette	7.65
12. Soda Springs	7.88
13. Meridian	8.76
14. American Falls	9.16
15. Buhl	9.18
16. Weiser	9.86
17. Emmett	10.39
18. Preston	14.28
19. Ketchem	17.45
20. Hailey	17.55
21. Council	17.67
22. Mountain Home AFB	18.36
23. Glenns Ferry	21.07
24. Cascade	21.58
25. Ammon	21.59
26. Mountain Home	22.90
27. Filer	24.78
28. Kimberly	24.96
29. Eagle	25.22
30. Kuna	27.82
31. Malad City	28.25
32. Ashton	33.13
33. Challis	37.99
34. Paul	40.91
35. Homedale	45.67
36. Hansen	54.21
37. Fairfield	55.84
38. Lava Hot Springs	72.19
39. Midvale	95.33
40. Idaho City	106.47
41. Grand View	185.62
42. Melba	196.37
43. Butte City	583.57
44. Stanley	765.26

## DIRECT UTILIZATION SITE ECONOMIC RANKING: MONTANA

SITE	\$/MILLION BTUS
1. Anaconda	4.99
2. Deer Lodge	7.35
3. Bozeman Hot Springs	15.17
4. Chico - Livingston	33.35
5. White Sulphur Springs	34.40
6. Camas Hot Springs	41.45
7. Livingston	50.07
8. Pipestone - Whitehall	58.76
9. Paradise	95.33
10. Avon	129.92
11. Gardiner	134.43
12. Hot Springs	146.40
13. Clancy	157.96
14. Grantsdale	164.67
15. Townsend	173.53
16. Lolo	185.22
17. Garrison	315.29
18. Medicine Hot Springs	1,033.29
19. Polaris	2,562.75
20. Sula	2,576.08
21. Toston	2,732.80

## DIRECT UTILIZATION SITE ECONOMIC RANKING: OREGON

SITE	\$/MILLION BTU
1. Hermiston	1.53
2. Ashland	3.23
3. Klamath Falls Area	4.02
4. The Dalles	5.50
5. LaGrande Area	5.19
6. Pendleton Area	7.62
7. Ontario Area	7.65
8. Vale High School Area	7.83
9. Oakridge Area	13.50
10. Paisley Area	10.72
11. Baker	16.33
12. Milton Freewater Area	20.13
13. Lakeview Area	21.79
14. Umatilla Area	32.25
15. Heppner Area	36.02
16. Burns Area	41.11
17. Union Area	43.27
18. Troutdale	45.02
19. Kahneeta Hot Springs Area	46.50
20. Irrigon Area	49.18
21. Stanfield Area	64.85
22. Rajneeshpuram	62.22
23. Boardman Area	81.58
24. Huntington Area	94.54
25. Government Camp	94.82
26. Parkdale	94.92
27. Pilot Rock Area	96.07
28. Echo Area	100.59
29. Arlington	109.04
30. Athena Area	112.25
31. Weston Area	145.40
32. Haines	173.19
33. Lexington Area	200.50
34. Adrian Area	249.71
35. North Powder	279.28
36. Cove Area	327.12
37. Spray	355.36
38. Jordan Valley	375.24
39. Ritter Hot Springs	418.57
40. Imbler	555.12

# DIRECT UTILIZATION SITE ECONOMIC RANKING: WASHINGTON

SITE	\$/MILLION BTU
1. Pullman	1.10
2. Ellensburg	1.22
3. Yakima	1.68
4. Sunnyside	1.91
5. Warden	2.07
6. Walla Walla	2.08
7. Prosser	2.11
8. Kennewick	2.80
9. Othello	2.91
10. Grandview	3.24
11. Toppenish	3.57
12. Cheney	3.67
13. Wenatchee	4.34
14. Zillah	6.52
15. Moses Lake	7.29
16. Connell	8.22
17. Pasco	8.40
18. College Park	8.49
19. Colfax	9.02
20. East Wenatchee	9.56
21. Granger	13.28
22. Ephrata	15.35
23. Richland	17.63
24. Clarkston	22.76
25. Stevenson	41.16
26. Soap Lake	59.79
27. Pomeroy	68.17
28. West Richland	94.95
29. Ritzville	116.06
30. Odessa	137.50
31. Harrah	138.68
32. Benton City	166.19
33. North Bonneville	182.63
34. Davenport	211.34
35. Mabton	214.17
36. Wahkiacus	329.20
37. Washtucna	377.27
38. St Martins Hot Spr Rsort	387.42
39. Lind	411.14



# HEATPLAN USER MANUAL

Version 2.0

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July, 1984

PREPARED BY

ELIOT ALLEN & ASSOCIATES, INC.

SALEM, OREGON

FOR THE

WASHINGTON STATE ENERGY OFFICE

## NOTICE

This Manual is an account of work for the Washington State Energy Office. Neither the Washington State Energy Office, nor any of its employees, contractors, subcontractors, or their employees makes any warranty, expressed or implied, or assumes any legal liability to third parties, for the content hereof. All opinions, findings, conclusions, and recommendations expressed in this Manual are those of the authors and do not necessarily reflect the views of the Washington State Energy Office.

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## 1. INTRODUCTION

HEATPLAN 2.0 is a microcomputer program designed to provide a neighborhood-level inventory of heat demands by type of land-use, and a preliminary assessment of district heating favorabilities for the neighborhoods. It is intended for use by local officials for purposes of:

- 1) Establishing a basis for heat supplies and demands as determinants in the community development process, where land-use planning can be used to optimize alternate energy use and district heating development; and
- 2) Identifying areas in communities where detailed engineering and economic assessments of current district heating opportunities may be warranted, and other areas where land-use incentives should be focused to improve long-term conditions for district heating.

The specifications of HEATPLAN 2.0 are summarized in Table 1. Although the program has been developed for the Washington State Energy Office, and the User Manual contains certain supplemental data specific to Washington, the program is capable of being used in any location where the necessary input data are available.

Table 1

HEATPLAN VERSION 2.0 SPECIFICATIONS

Program Language

Microsoft Basic Interpreter<sup>1</sup>

Operating System

MS-DOS

Random Access memory Required

128K bytes

Disk Drives Required

Floppy disk drives

Disk Size and Format

IBM PC or compatible 5  $\frac{1}{4}$ "

Printer Required

Any printer capable of printing 80 characters wide. Output is formatted for 8  $\frac{1}{2}$  x 11-inch paper.

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<sup>1</sup> MS-DOS and Microsoft BASIC are registered trademarks of Microsoft, Inc.

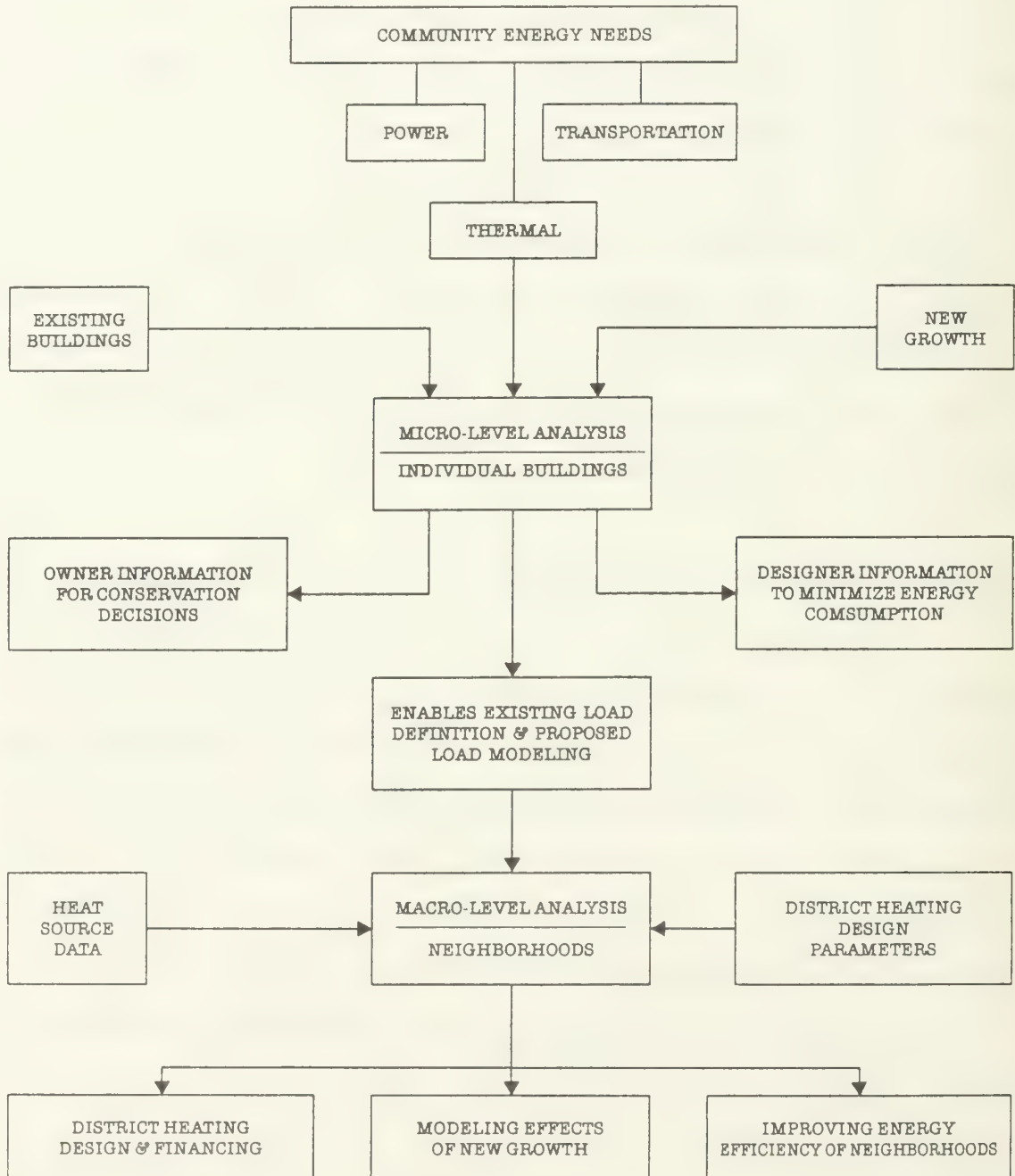
## A Land-Use Planning Approach to District Heating

HEATPLAN approaches district heating from the premise that a community's heat supplies and demands should be important determinants in the community development process. In northern climates, such as Washington's, space and water heating can account for a major portion of a community's total energy consumption. Industrial processing can add still more heat demands. By integrating heat supplies and demands with traditional development determinants, it is suggested that a community can create a land-use arrangement that is not only more energy-efficient, but also specifically conducive to district heating. The community heat planning process is shown diagrammatically in Figure 1.

Community heat loads are a direct function of land-uses. The types, locations, densities, and mixes of land-uses in a community will control its suitability for district heating. Moreover, land-use locational relationships to alternate energy sources, such as geothermal, biomass, or waste heat sites, will determine the suitability of such heat sources for district heating operations. In short, a community's land-use plan must create sufficiently high densities and diversities of heat loads, in close proximity to alternate heat sources, in order for district heating to be feasible.

Figure 1

THE COMMUNITY HEAT PLANNING PROCESS



In addition to meeting the design and economic prerequisites of district heating, land-use planning can also be used to achieve related community objectives in conjunction with district heating, such as neighborhood renewal or economic diversification. New businesses and other property investments may be induced, in part, through the availability of low cost renewable energy supplied by a district heating system.

HEATPLAN evaluates a community according to the heat demands of its land-uses; the heat supplies that geothermal, biomass, or waste heat can offer; and the resulting favorability for district heating on the basis of heat demand per unit of land area, and the cost-effectiveness of serving such demand through a district system. The program estimates the minimum heat price and minimum heat sales per unit of land area necessary for successfully operating a community-wide system. It then compares each neighborhood's heat demands with the necessary community-wide minimum, and the resulting heat density ratio constitutes a favorability rating for each neighborhood, indicating either its suitability for district heating, or the need for appropriate land-use changes, e.g. increased development densities. The program's neighborhood rating formula is shown in Table 2. A detailed discussion of land-use planning measures to improve district heating favorabilities is contained in Appendix L.

HEATPLAN is intended for use by local officials concerned with land-use planning, community energy management, and energy

Table 2

HEATPLAN DISTRICT HEATING FAVORABILITY RATINGS

$$\text{Study Area Favorability Ratio} = \frac{\text{Study Area Net Density of Annual Heat Use (MBtu/acre/year)}}{\text{Minimum Heat Sales Needed for Community-Wide Operations (MBtu/acre/year)}}$$

<u>Favorability Ratio</u>	<u>Favorability for District Heating</u>
>1.98	VERY FAVORABLE
1.44 - 1.98	FAVORABLE
0.57 - 1.43	POSSIBLE
0.34 - 0.56	QUESTIONABLE
<0.34	UNFAVORABLE

resource development. It is recommended, however, that advice be sought from appropriate resource and engineering professionals when using HEATPLAN in order to improve its reliability. New users should review the User Manual to become familiar with program concepts, terminology, and input requirements before executing program runs.

User-supplied information and override capabilities give HEATPLAN the versatility to be used over time with increasingly refined inputs. Thus, initial runs using rough estimates of values can be replaced with more exact engineering and economic data acquired over time. This program versatility also applies to sensitivity analysis, where, by changing key values, the user is able to simulate the effects of different heating load, system design, or financing circumstances.

It should be noted that computer models must inherently contain certain assumptions about project circumstances in order to be used in as many locations and cases as possible while performing the same function. HEATPLAN's assumptions have been developed to reflect as closely as possible the state-of-the-art and actual district heating experiences. Where subjective judgments or assumptions have been unavoidable they are purposely conservative. Because assumptions can detract from the accuracy of the model, HEATPLAN has been designed to permit overriding of its major assumptions, and insertion of actual local or engineered values whenever available. However, no claim or

warranty is made regarding the validity of HEATPLAN results when used for engineering purposes; rather, results should be used for comparative analysis of alternatives where percentage increases or decreases are compared to one another, rather than for the determination of actual numeric results.

HEATPLAN is intended to be a data management system that can be used as a community planning tool. District heating prospects can be identified by HEATPLAN, but detailed engineering and economic analyses will always be required in order to actually implement district heating projects.

## 2. USING THE PROGRAM

### Program Organization

HEATPLAN is organized, as shown in Figure 2, according to a sequence of program "modules" that quantify heating load, design a district heating system to serve the load, calculate life-cycle economics for the system, and rate neighborhood favorabilities for district heating in terms of their heat density. The modules and their functions are summarized as follows:

#### Module 1 - Heat Load Information

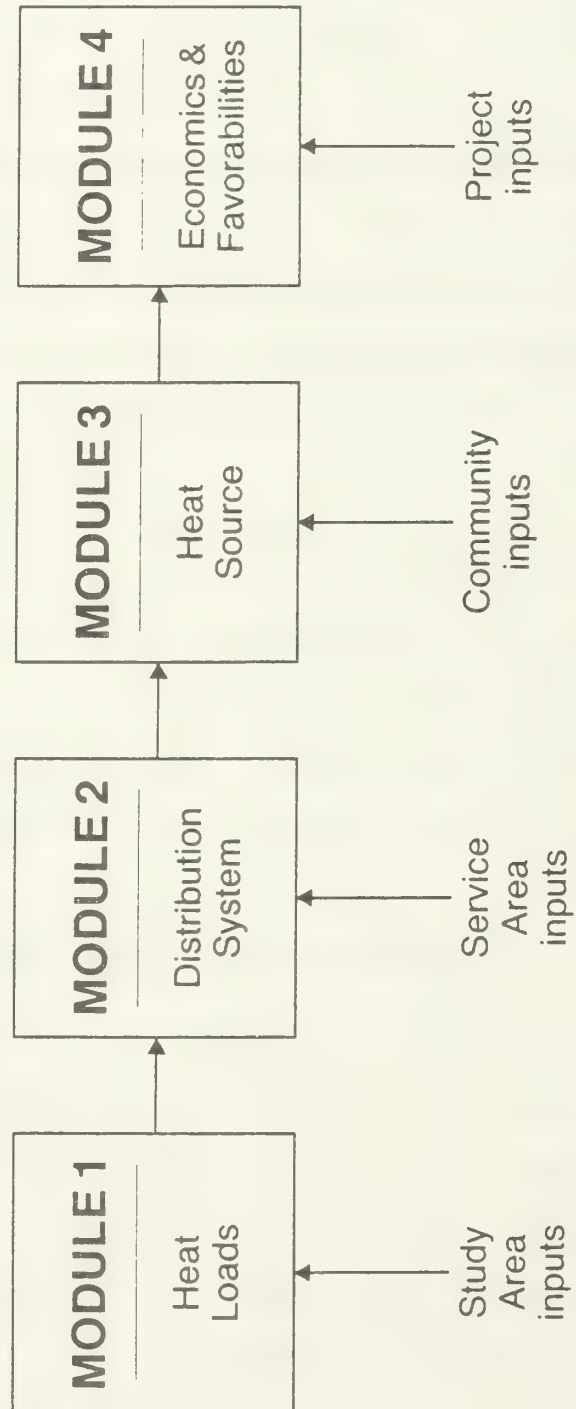
This module holds information on the community, its climate, and heat demands inventoried by building types in neighborhood "study areas." Heat demands can include space and water heating, and industrial process heating.

#### Module 2 - Distribution System Information

This module allows the user to select any combination of neighborhood "study areas" to be served by a district heating system in a common "service area." Study areas are aggregated in terms of their heating loads and land area, thereby serving as a basis for designing and costing a distribution pipeline network.

Figure 2

PROGRAM ORGANIZATION



### Module 3 - Heat Source Information

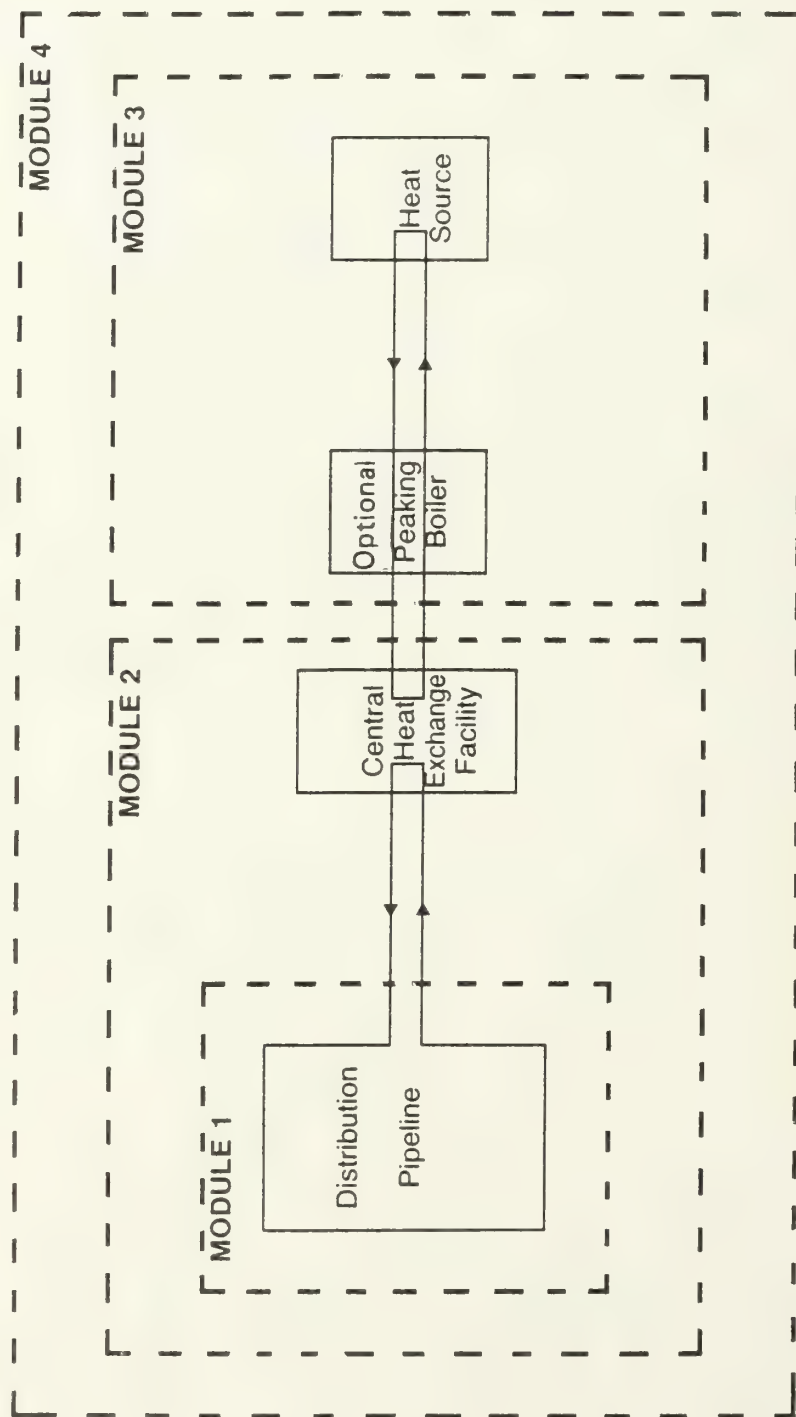
This module allows the user to select either a geothermal, biomass, or waste heat source for the system, and includes the design and costing of connecting the heat source to the distribution system established in Module 2.

### Module 4 - Life-Cycle Economics and Favorability Ratings

This module holds information on economic and financial parameters for the total system, which are used to estimate life-cycle costs. The results of this module include a district heat sales price necessary for successful operations, and study area favorability ratings based on the area's ability to generate an acceptable level of heat sales.

The relationship of these modules to the district heating system which is conceptualized by HEATPLAN is shown in Figure 3. Thus, Module 1 is used to identify the customers and their heating loads to be served by the system; Module 2 is then used to design and cost a central heat exchange facility and distribution pipeline network to serve the customers; Module 3 is used for selecting a heat source which can be delivered by transmission pipeline to the central heat exchange facility, with an option for conventional fuel peaking to reduce demands on the primary heat source; and Module 4 encompasses capital and operating costs for the entire system over its useful life, resulting in a

Figure 3  
RELATIONSHIP OF PROGRAM MODULES TO CONCEPTUAL DISTRICT HEATING SYSTEM



calculation of the price the district heat must be sold at, and the favorability of each neighborhood study area in meeting minimum sales requirements.

The district heating assessment which HEATPLAN performs is geographically organized on two levels: 1) neighborhood "study areas"; and 2) a district heating system "service area" which can encompass any combination of neighborhood study areas. As shown in Figure 4, a community is first divided into small-scale neighborhood study areas (a detailed discussion of study area sizing is provided in Appendix F). A maximum of 99 study areas can be processed by HEATPLAN. Following the delineation of neighborhood study areas and inventorying of their heating loads, they can be aggregated in any contiguous combination to represent a district heating system's service area. HEATPLAN is designed to allow users to form any variety of study area combinations and service area boundaries in order to accommodate different development scenarios or site-specific community conditions.

The program's flexibility in aggregating heating loads and delineating service boundaries is continued in the district heating system's design and costing by allowing for discrete development cases to be evaluated. As shown in Figure 5, the heating loads of neighborhood study areas can be defined according to existing conditions, or modeled to simulate alternative heating loads under different development scenarios; the study areas can then be aggregated in Module 2 to form any

Figure 4  
RELATIONSHIP OF STUDY AND SERVICE AREAS TO THE OVERALL COMMUNITY

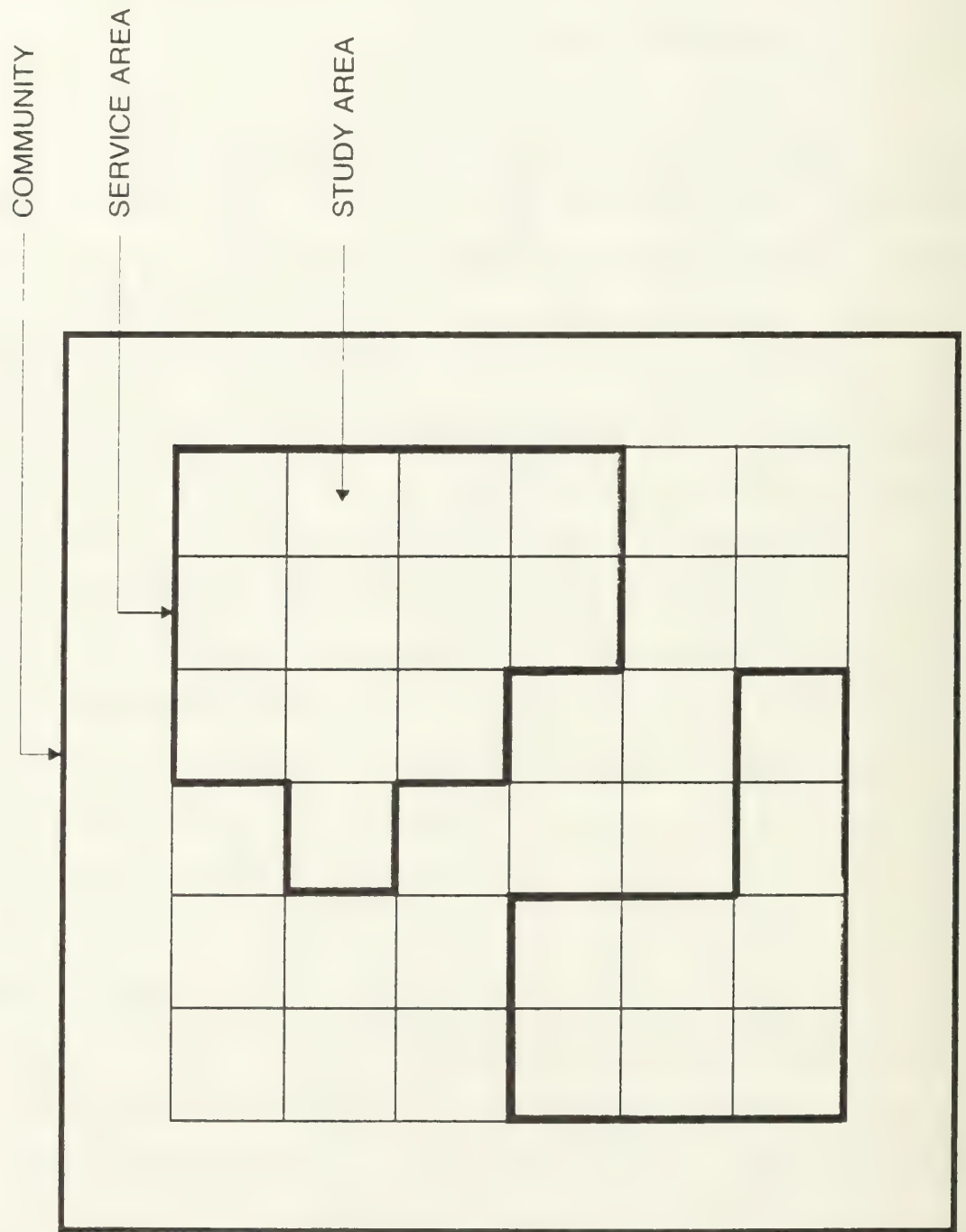
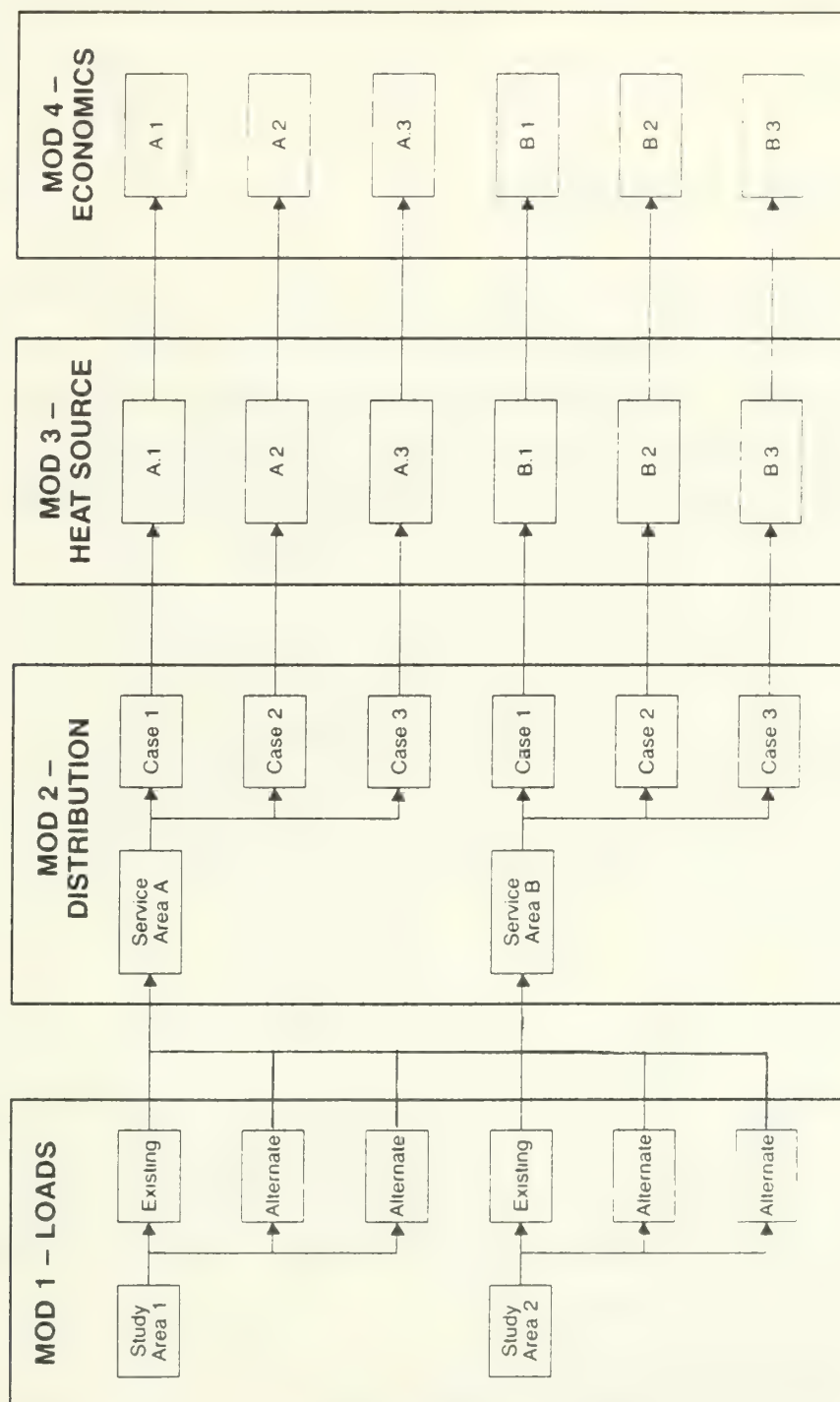


Figure 5  
STRUCTURING PROGRAM CASES



variety of system service area, and a specific distribution system case can be defined. This case can then be passed through Module 3 for the necessary heat source inputs, and onto Module 4 for life-cycle costing and study area favorability rating. In addition to the ability to define a major case, the program offers the user an opportunity to simultaneously run five subcases for certain system parameters. These subcase options are intended to facilitate sensitivity analysis of a project, wherein a user can readily see the effect of changing key system parameters in one program run.

### Preparing HEATPLAN Diskettes

Before using the program, a system disk and a data disk must be prepared. Start your system with a copy of your DOS diskette in drive A: (lefthand side); if necessary, refer to your computer system documentation for instructions. Label one blank diskette as **HEATPLAN System Disk** and a second as **HEATPLAN Data Disk**. First prepare your HEATPLAN Data Disk for use by placing it in drive B: (righthand side). At the DOS **A>** prompt, type the command below to format the diskette:

#### **FORMAT B: (Enter)**

When formatting is complete, the prompt **Format another (Y/N)?** will appear. Respond by typing **N**. The HEATPLAN Data Disk is now ready for use. Remove it from the drive and put it aside. Begin preparation of your HEATPLAN System Disk by placing it in drive B: Format the diskette and transfer a copy of DOS to it by typing the following command at the **A>** prompt:

#### **FORMAT B:/S (Enter)**

When formatting is complete, the prompt **Format another (Y/N)?** will appear. Again, respond by typing **N**. Next, your BASIC language interpreter must be copied to the System Disk by typing the command below. Check your computer system documentation for the name of your BASIC interpreter. If it is not called **BASICA**, substitute its name for **BASICA** in the command:

#### **COPY BASICA.\* B:/V (Enter)**

Now remove both diskettes from the drives. Place the newly formatted HEATPLAN System Disk in drive A: and place our original HEATPLAN Programs disk in drive B:. Transfer the HEATPLAN programs to your HEATPLAN System Disk by typing the following command from the DOS A> prompt:

**Copy B:\*.\*/V (Enter)**

Preparation of your working copies of HEATPLAN is now complete.

The files on the HEATPLAN program disk are listed in Table 3 . The files created on data disks are titled first by the number of the Module to which the data applies, followed by the first three letters of the community's name, the service area name, and the case name respectively. For example, Module 2 data for Spokane's "Downtown" service area in a case named "Initial Phase," will appear on the data disk directory as: 2SP0-D0W-INI.

Table 3  
HEATPLAN VERSION 2.0 PROGRAM FILES

<u>File Abbreviation</u>	<u>Program Files</u>
MENU	Listing of modules
MOD1	Module 1
MOD2	Module 2
MOD3	Module 3
MOD4	Module 4
GEODT	Geothermal heat exchanger temperature drop values
STRGEODT	GEODT storage
LSTBAS	Source code listing

## Running HEATPLAN

Use of the HEATPLAN program currently requires two floppy disk drives. Begin by starting your computer ('booting' DOS) according to the instructions provided with your system. Place the HEATPLAN System Disk in Drive A: (lefthand side) and the HEATPLAN data disk in drive B: (righthand side). Load your BASIC language interpreter and run the HEATPLAN program by typing the command below at the DOS **A>** prompt. Check your computer system documentation for the name of your BASIC interpreter. If it is not called BASIC A, substitute its name for **BASICA** in the command.

### **Basica Menu (Enter)**

BASIC will load and display a sign-on message, and a menu (list of choices) will appear on the screen. From this point forward, all HEATPLAN functions will be selected from this menu. The user will note that in addition to Modules 1 through 4, the Menu also displays Modules 5 and 6. Module 5 is simply a command which lists all files that have been created on the data disk. Module 6 is simply a command to exit the HEATPLAN program.

Once an initial run has been made through all four Modules, the user may rerun any Module using a previously entered case. For example, if a complete run has been executed assuming a geothermal heat source in Module 3, the user may return to the program and begin rerunning Module 3 using a biomass heat source without having to rerun Modules 1 and 2.

## Program Execution

This section of the manual provides a step-by-step description of the program content as it appears on the computer screen and in hard output. Program statements are paraphrased in bold type below. Sample output for a complete run is provided in Appendix A for further reference.

The objective of this description is to allow the user to preview and become familiar with the program's content and operation, and to help the user prepare the necessary input data required to execute program runs. A set of program input worksheets is also provided in Appendix B to help organize input data and plan case parameters.

## Module 1

PRINT OR DO NOT PRINT OUTPUT TO LINE PRINTER.

This option is offered at the beginning of each Module. If the "no print" option is selected users are cautioned that output cannot be printed at a later time; thus, the "no print" option should only be used when a permanent record of program results is not desired.

ENTER COMMUNITY NAME.

MODIFYING EXISTING COMMUNITY OR BEGINNING NEW COMMUNITY?

In addition to the user's initial run, i.e. "beginning a new community" it is also possible to rerun Module 1, i.e. "modifying existing community," to either change data for study areas entered previously, or to add new study areas.

ENTER DATE IN MM/DD/YY FORMAT.

This is the date of the program run, and is intended to aid the user in recording different runs over time. The date

must be entered according to the two digit format shown, e.g. July 2, 1984 would be entered as 07/02/84.

#### ENTER COMPOUND INFLATION RATE FROM 1983 TO DATE.

This feature enables the program's cost estimates to be kept current with present day equipment and construction costs. The compounded inflation rate since 1983 which is entered here is used throughout the program to update its capital cost calculations.

#### ENTER LOCAL ANNUAL HEATING DEGREE DAYS.

This is a measurement of coldness over time calculated by subtracting the community's mean temperature from a reference temperature of 65°F. The resulting number equals heating degree days for a 24-hour period, which is then multiplied by 365 days to arrive at an annual number. Normally district heating becomes favorable when annual heating degree days exceed 4,000. Degree days for selected locations in Washington are listed in Appendix D.

#### ENTER WINTER OUTSIDE DESIGN TEMPERATURE.

This is the reference temperature expected to be exceeded 99% and 97.5% of the year for wood and masonry structures respectively. In effect, this temperature reflects the coldest possible case that building heating systems are designed to accommodate. Winter outside design temperatures

for selected locations in Washington are listed in Appendix E, with a discussion of how to select the temperature most appropriate for the types of buildings being evaluated by the program.

#### ENTER STUDY AREA NUMBER AND GROSS LAND AREA.

The user should assign a unique number to each study area, and enter the total amount of land area within it, in acres. HEATPLAN will process up to a maximum of 99 study areas in a given service area. The selection of study area size and configuration is an important factor in producing reliable program results, with smaller study areas producing the greatest level of detail, and therefore the highest reliability in program output. Further discussion of study area sizing and configuration is provided in Appendix F. It is also important to note that alternative load scenarios for a given study area can be modeled by the program. This can be accomplished by reentering a study area number for an area which has already been entered, and simply adding a decimal point and additional number to denote the alternative case being modeled. For example, the actual land-uses presently existing in an area would be entered as Study Area 3, and two different scenarios for future growth in the same area could be entered as Study Area 3.1 and 3.2. As will be explained below in Module 2, the user can then include any one of the three study area scenarios in assessing district heating favorabilities. This feature can

be particularly useful in evaluating different land-use designations and zoning densities for a given study area.

ENTER ANY ACTUAL HEATING LOAD DATA AVAILABLE FOR STUDY AREA ACCORDING TO: ANNUAL SPACE HEATING, ANNUAL WATER HEATING, PEAK INDUSTRIAL PROCESS HEATING, AND ANNUAL INDUSTRIAL PROCESS HEATING.

The entry of actual heat load values for major facilities in a study area, e.g. school, hospital, or industry, is an important factor in improving the program's accuracy. Because such large facilities tend to have unique heat consumption characteristics, and because their large size has a significant impact on a given area's district heating favorability, it is more reliable to obtain their actual heat values than to rely on the program's primary method of estimating load by floor space coefficients. The collection and entry of actual load data is discussed further in Appendix G.

THE PROGRAM ASSUMES AN ACTUAL SPACE HEATING LOAD FACTOR OF 25%. ENTER OVERRIDE IF DESIRED.

In order to derive an estimate of the peak space heating load from the actual annual value entered above, the program must use a "load factor," which represents the percentage of time during the year that a heating system is operating at its full capacity. The program's default value is 25%;

however, the user may override this value with a facility specific value derived from actual facility records.

ENTER TOTAL SQUARE FOOTAGE FOR BUILDINGS IN STUDY AREA, EXCLUSIVE OF ANY BUILDINGS FOR WHICH ACTUAL LOAD VALUES WERE ENTERED ABOVE.

ENTER FOOTAGE ACCORDING TO DATE OF CONSTRUCTION CATEGORIES OF HIGH CONSUMPTION (BEFORE 1955), AVERAGE CONSUMPTION (1955-1975), OR LOW CONSUMPTION (AFTER 1975).

ENTER TOTAL SQUARE FEET BY YEAR OF CONSTRUCTION FOR THE FOLLOWING BUILDING TYPES: SINGLE-FAMILY, MULTI-FAMILY, MOBILE HOME, HOTEL/MOTEL, OFFICE, RETAIL, RESTAURANT, PUBLIC ASSEMBLY, AND WAREHOUSE.

This is the program's primary method of estimating heating loads for study areas. Using floor space information the program estimates peak and annual space and water heating demands for each building type, and then sums them for the entire study area. This input item can be used to described existing conditions in study areas or to model proposed or potential new construction by simulating the amount of floor space to be built in an area. Collection of this information represents one of the user's most important inputs, and sufficient time should be devoted to this task to assure reliable program results. The collection of building floor space data is discussed further in Appendix H.

THE PROGRAM USES A TYPICAL PEAK HEATING LOAD DIVERSITY FACTOR OF 70%. ENTER AN OVERRIDE IF DESIRED.

This item accounts for the fact that peak heating loads do not occur simultaneously in all buildings in an area, and therefore requires that the sum of individual peak loads be reduced in order to accurately estimate the total heat needs for an area. The program's default value of 70% is considered typical of most urban areas; however, the user may increase this value in study areas having predominantly one type of land-use (and consequently a greater concurrence in peak demands); or alternatively, decrease the value in areas which have highly diverse land uses (and consequently fewer concurrent peak demands).

THE PROGRAM ASSUMES A TYPICAL DISTRIBUTION HEAT LOSS OF 5%. ENTER OVERRIDE VALUE IF DESIRED.

This item accounts for the relatively small amount of heat lost in distributing hot water through a pipeline network to customers; in effect, this heat loss must be added onto the load demands for an area, again in order to accurately estimate the total heat needs of the area. The 5% default value is considered typical for urban district heating systems, but the user can override this value to accommodate site-specific conditions.

ENTER INITIAL AND ULTIMATE MARKET PENETRATION RATES EXPECTED FOR DISTRICT HEATING IN THE STUDY AREA.

Having inventoried the total heating demands of the study area, the user must estimate the amount of this heating "market" that the district system is expected to capture, i.e. the number of customers that are likely to be initially connected during the system's first year of operation, and the number that are likely to be ultimately connected by the end of the system's useful life. This input greatly influences the sizing and economics of the system being conceptualized by the program, and the user should carefully weigh the values to be entered. Market penetration for district heating will be determined by a variety of factors, such as the types of building heating systems already in place, and the competitiveness of the district heating price compared to conventional heating fuels. Further discussion of market penetration rates is given in Appendix I.

This completes the inputs for Module 1. At this point the program calculates and prints the load characteristics for the study area, and allows the user to process additional study areas or continue onto the next Module.

## Module 2

PRINT OR DO NOT PRINT OUTPUT TO LINE PRINTER.

This is the same option as described above in Module 1.

ENTER COMMUNITY NAME.    ENTER DATE.    ENTER SERVICE AREA NAME.  
ENTER CASE NAME.

These identification inputs enable the program to retrieve study area data files from Module 1 according to the community's name, and to further identify subsequent portions of the program run according to Service Area and Case names. As indicated earlier, data disk files are titled according to a four-part identification of Module number, Community name, Service Area name, and Case name. The user is cautioned that only the first three letters of each name are read by the program as a file identifier, and therefore different Service Area or Case names must have different combinations of the first three letters in the name in order for separate data files to be created; otherwise the program will over-write and erase a previous data file with the same first three letters in the name. For example, if a Service Area was named SOUTHWEST in one run, and the user attempted to execute a second run or a different Service Area named SOUTHEAST, because the first three letters of both Service Area names are the same, the program would overwrite and erase the first data file. Users should choose Service Area

and Case names carefully so as not to duplicate the first three letters in different names.

ENTER NUMBER OF SUBCASES TO BE EVALUATED WHEN OFFERED AS AN OPTION FOR USER INPUTS.

This feature enables the user to perform sensitivity analyses during one program run by simultaneously calculating results for up to five subcases of a primary case. It should be noted that the number of subcases selected at this point in the program will apply through completion of Module 4 for a given case. Users are cautioned that changes in key values must be internally consistent within a given subcase in order to produce reliable program results.

STUDY AREAS WHICH HAVE BEEN LOADED ARE: (PROGRAM LISTS ALL STUDY AREA NUMBERS ENTERED IN MODULE 1). ENTER STUDY AREA NUMBERS TO BE INCLUDED IN SERVICE AREA. TYPE "COMPLETE" WHEN ALL NUMBERS ARE ENTERED.

This step allows the user to combine any combination of study areas entered in Module 1 into the service area to be served by the district heating system.

THE TOTAL DIVERSIFIED PEAK LOAD FOR THE SERVICE AREA ADJUSTED FOR ULTIMATE MARKET PENETRATION IS ESTIMATED TO BE \_\_\_\_\_ BTU/HR. THE TOTAL ANNUAL LOAD FOR THE SERVICE AREA ADJUSTED FOR ULTIMATE

MARKET PENETRATION IS ESTIMATED TO BE \_\_\_\_\_ BTU/YR. ENTER  
OVERRIDE VALUES IF DESIRED.

These are the program's estimates of peak and annual heating load for all the study areas which were combined in the previous step into a common service area. As noted in the statement, the load estimates have been adjusted to reflect the heat demands at the ultimate market penetration level; in other words, this establishes the size of distribution system necessary to serve the full load expected over the system's useful life. Users can override these estimates to simulate changes in a service area's load, such as an increase from significant growth, or alternatively reduced demands as a result of a major building weatherization project.

THE INITIAL DISTRICT HEATING MARKET SHARE IS \_\_\_\_\_. ENTER  
OVERRIDE IF DESIRED.

This is the weighted average initial market penetration rate for the study areas which were combined into a common service area. Rather than return to Module 1 to model the effects of different penetration rates, this step can be used to simulate a similar change for the entire service area.

ENTER LENGTH OF PROJECT LIFE FROM 10 TO 25 YEARS.

This input allows the user to define the expected useful life of the district heating system. This input is used throughout the remainder of the program for projecting market penetration and life-cycle costs.

IF DESIRED ENTER OVERRIDE MARKET SHARES EXPECTED FOR DISTRICT HEATING IN THE SERVICE AREA FOR EACH YEAR OF THE PROJECT'S OPERATING LIFE.

In this step the program automatically models market penetration as an "S" curve beginning at the weighted average initial penetration shown above, and ending at the weighted average ultimate penetration for the service area. The curve that is modeled by the program is based on typical district heating penetration experiences in other communities (see Appendix I). The user may override these values and model a penetration curve to reflect local site-specific circumstances.

THE TOTAL GROSS ACREAGE OF THE SERVICE AREA IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE VALUE IS DESIRED.

This is the sum of the acreage for all the study areas that were combined into a common service area. This value is used below in the program's calculation of distribution pipeline, and the user may override the calculated value to account for factors such as large dedicated open spaces

(which should be eliminated, or as an alternative method of to simulating higher or lower development densities in the service area.

SELECT DISTRIBUTION PIPELINE INSTALLATION COST CORRECTION FACTOR FROM THE FOLLOWING: 1.0 FOR HIGHLY URBANIZED SERVICE AREA WITH UNCERTAIN EXISTING UTILITY LOCATION IN RIGHTS-OF-WAY; 0.75 FOR HIGHLY URBANIZED SERVICE AREA WITH KNOWN UTILITY LOCATIONS IN RIGHTS-OF-WAY; 0.50 FOR MODERATELY URBANIZED SERVICE AREA; OR 0.35 FOR SPARSELY URBANIZED SERVICE AREA.

This input allows the user to account for the different costs required to install distribution pipe in different urban settings. The four cost correction factors generally describe the following conditions: 1.0 for cities exceeding a population of 100,000 where all rights-of-way are paved; 0.75 for cities of 20,000-100,000 persons, where 80-100% of the rights-of-way are paved; 0.50 for cities of 2,000-20,000 persons, where 50-80% of the rights-of-way are paved; and 0.35 for cities of less than 2,000 persons, where less than 50% of the rights-of-way are paved. This step assumes that pipeline trenches are constructed in soil that does not require drilling or blasting; and that pavement must be removed and replaced for trenching. Distribution pipe is assumed to be directly buried, and does not include lateral service lines to customer buildings. The program assumes that service lines and building retrofits will be customer responsibilities.

ENTER DISTRIBUTION FLUID SEND-OUT TEMPERATURE, FROM 95 TO 210OF.

This is the user's estimate of the temperature of the hot water to be circulated from a central heat exchange facility to customers of the system. In cases where the intended heat source (geothermal, biomass, or waste heat) exceeds 130OF, the user should enter an assumed send-out temperature of approximately 10 degrees less than the heat source temperature. In cases where the heat source temperature is below 130OF the user should enter an assumed send-out temperature of 120OF or less. The program automatically designs and costs for insulated distribution pipe at send-out temperatures above 120OF, and uninsulated pipe below that temperature. Thus, the user can simulate the effects of insulated versus uninsulated pipe in selecting the assumed send-out temperature.

THE PROGRAM ASSUMES A 75° DISTRIBUTION LOOP RETURN TEMPERATURE.  
ENTER OVERRIDE IF DESIRED.

The program's default value of 75° is considered a base case return temperature, and the user may override this default to reflect a different amount of heat extraction by customers on the distribution loop. Generally, 40 to 60 degrees F of heat should be able to be extracted by customers on a distribution loop.

THE PROGRAM CALCULATES THE DISTRIBUTION PIPELINE LENGTH TO BE \_\_\_\_\_ FEET. ENTER OVERRIDE IF DESIRED.

The program calculates distribution pipeline length as a function of the service area acreage estimated above. This value is expressed in linear footage, and the user may override the program's estimate in order to account for site-specific conditions such as street patterns or particular locations of major heat users within the area.

PUMPING HEAD IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the amount of pumping head, in feet, that is estimated to be required for circulating distribution fluids based on the length of the distribution pipeline. The user may override this estimate to account for unusual site-specific conditions, such as large differences in elevation within a service area.

THE PROGRAM ASSUMES A DISTRIBUTION PUMP EFFICIENCY OF 70%. ENTER OVERRIDE IF DESIRED.

This item uses a default value of 70% which is typical of pump efficiencies, and is taken into account in order to accurately estimate pump costs.

THE DISTRIBUTION PUMP CAPITAL COST IS ESTIMATED TO BE \_\_\_\_\_.  
ENTER OVERRIDE IF DESIRED.

This estimate is derived from the foregoing inputs, based on a cost coefficient factor for typical circulation pumps (see Appendix M for a detailed description of the program's cost coefficients).

THE PROGRAM ESTIMATES THE COST OF A CENTRAL HEAT EXCHANGE AND CONTROL BUILDING AT \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the estimated cost to construct a building to house the system's central heat exchanger (or heat pump if needed for low-temperature heat sources), and controls. The estimate is based on a minimum size of 1,200 square feet, plus an additional 250 square feet for each 1,000 gpm of distribution flow capacity. The user may override this value in a case where an existing structure is available to house the necessary equipment.

THE CENTRAL HEAT EXCHANGER (AND HEAT PUMP IF HEAT SOURCE IS LESS THAN 120°F) CAPITAL COST IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the estimate of cost to equip the central facility with a stainless steel plate heat exchanger for heat sources above 120°F, or a water-to-water heat pump for sources beneath 120°F.

THE TOTAL CAPITAL COST FOR THE DISTRIBUTION SYSTEM IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the program's summation of all distribution capital costs estimated thus far.

THE INITIAL MAINTENANCE COST FOR THE DISTRIBUTION SYSTEM IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the program's estimate of initial maintenance cost as a fraction of the capital costs calculated above. Maintenance costs are assumed to be 1% of capital costs for non-moving parts, and 5% of capital cost for moving parts.

ENTER COST OF ELECTRICITY IN DOLLARS PER KILOWATT HOUR.

The user must enter the local electrical rate applicable to the system's operator, i.e. either a municipal or commercial rate. Ideally, the rate entered should be a weighted average rate that includes both energy and demand charges. Assistance in calculating this rate can be obtained from the user's local electrical utility.

THE DISTRIBUTION SYSTEM'S TOTAL INITIAL OPERATION AND MAINTENANCE COST IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the program's summation of the maintenance costs calculated above together with the electrical costs for pumping, and, if applicable, operating the central

facility's heat pump. Heatpumps are assumed to operate at coefficients of performance that range from a low of 3.0 using 60°F source water, to a high of 15.0 using a 120°F source water.

### Module 3

PRINT OR DO NOT PRINT OUTPUT TO LINE PRINTER.

This is the same option described at the beginning of the two previous Modules.

ENTER COMMUNITY NAME. ENTER DATE. ENTER SERVICE AREA NAME.  
ENTER CASE NAME.

Except for the date entry, these identifiers will represent a continuation of data file names from Module 2.

TYPICAL VALUES FOR THE PERCENTAGE OF THE TOTAL ANNUAL LOAD TO BE MET IN EACH MONTH ARE GIVEN. ENTER OVERRIDE IF DESIRED.

At this step the program displays a typical annual load curve which describes colder winter months and warmer summer months. The user may override these values to create a load curve specific to unique community conditions, e.g. a service area load which is primarily industrial, and which either has a flat or constant load throughout the year, or which experiences heavier loads during summer months as a function of the process involved (for example, food processing).

SPECIFY HEAT SOURCE: WASTE HEAT, BIOMASS, OR GEOTHERMAL.

This selection determines the heat source for the district heating system. The choice made here is followed by a series of program steps which are specific to each of the three possible heat sources. These are listed below for geothermal first, and biomass and waste heat second. Further discussion of heat source options is provided in Appendix J.

GEOTHERMAL WILL OR WILL NOT BE PEAKED WITH CONVENTIONAL FUEL.

This is an option given for either relying totally on geothermal resources to meet the system's demands, or for including a conventionally-fueled boiler which will meet a portion of the peak demands, and thereby reduce the amount of geothermal resources required for system operations.

THE PROGRAM ASSUMES THAT 50% OF THE PEAK LOAD WILL BE MET BY THE GEOTHERMAL RESOURCE. ENTER OVERRIDE VALUE IF DESIRED.

The program uses a default value of 50% as typical of peaking configurations in district heating systems. The user may override this value to put a greater or lesser reliance on the geothermal resource.

ENTER THE FOLLOWING GEOTHERMAL DATA AND RELIABILITY LEVELS: 1.0 FOR TEST RESULTS FROM EXISTING WELLS TO BE USED IN THE PROJECT; 0.9 FOR AN ESTIMATE BASED ON WELLS IN THE SAME PRODUCTION FIELD;

0.8 FOR AN ESTIMATE BASED ON WELLS IN SIMILAR AREAS; OR 0.6 FOR AN ESTIMATE BASED ONLY ON SURFACE GEOLOGICAL INFORMATION AND LITERATURE REVIEW. ENTER GEOTHERMAL DATA AND RELIABILITY VALUES FOR: MAXIMUM PRODUCTION WELL FLOW RATE, WELLHEAD TEMPERATURE, DEPTH TO PRODUCTION ZONE, AVERAGE DRILLING AND CASING COST, AND STATIC WATER LEVEL BELOW GROUND LEVEL.

These inputs describe the geothermal resource characteristics and requirements for development. The resource input data should be obtained from local geothermal studies, professional geologists, and/or local well drillers. The reliability values are a measure of certainty of the estimate, and serve to account for design and cost risks in utilizing geothermal resources which are unconfirmed or untested. Further information on geothermal heat source characterization is provided in Appendix J.

THE GEOTHERMAL SYSTEM'S USABLE HEAT OR TEMPERATURE DROP ACROSS THE HEAT EXCHANGER IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the program's estimate of the amount of heat that can be extracted from the geothermal resource at the central heat exchange facility. The user may override the estimated value to simulate differing efficiencies for heat exchangers and/or heat pumps.

THE TOTAL NUMBER OF GEOTHERMAL PRODUCTION WELLS IS ESTIMATED TO BE \_\_\_\_ WELLS. ENTER OVERRIDE IF DESIRED.

Based on the resource characteristics entered above, the program makes this estimate of the number of production wells required to meet the system's demands. The user may override the estimated value to reflect the availability of existing wells, or to account for unusual site-specific geological and/or hydrological conditions which may necessitate a lesser or greater number of wells.

THE TOTAL NUMBER OF GEOTHERMAL INJECTION WELLS IS ESTIMATED TO BE \_\_\_\_ . ENTER OVERRIDE IF DESIRED.

This is the program's estimate of the number of injection wells required based on a ratio of 1 injection well to 2 production wells. The user may override this estimate in cases where injection is not going to be used, or where site-specific conditions necessitate a different ratio between injection and production wells.

ENTER NUMBER OF GEOTHERMAL REPLACEMENT WELLS EXPECTED TO BE REQUIRED OVER THE LIFE OF THE PROJECT. ENTER POTENTIAL NUMBER OF GEOTHERMAL DRY HOLES TO BE DRILLED OVER THE LIFE OF THE PROJECT.

These inputs allow the user to account for well replacement which may be required over the life of the system, and for unsuccessful wells that may be drilled.

#### ENTER EXPECTED DRAWDOWN IN PRODUCTION WELLS.

The user should enter the amount of drawdown, in feet, expected when production wells are pumped at their maximum flow rate. This value is used below for calculating pumping requirements.

#### ENTER GEOTHERMAL EXPLORATION AND LAND COSTS.

This input allows the user to account for expenses that may be incurred in using consulting geologists and/or hydrologists for siting wells, and for acquiring well sites.

THE TOTAL CAPITAL COST OF GEOTHERMAL WELLS OVER THE LIFE OF THE PROJECT IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the program's summation of all geothermal capital costs estimated thus far.

ENTER GEOTHERMAL TRANSMISSION PIPELINE RIGHT-OF-WAY DISTANCE FROM THE MOST FAVORABLE GEOTHERMAL RESOURCE SITE TO THE CENTRAL HEAT EXCHANGE FACILITY LOCATION.

The user should enter the distance, in miles, from the intended geothermal production area to the location of the central heat exchange facility. It is important that this distance be measured according to the rights-of-way that the pipeline will be installed in. See Appendix J for further discussion of transmission pipeline routing.

SELECT GEOTHERMAL TRANSMISSION PIPELINE INSTALLATION COST  
CORRECTION FACTOR.

The program offers the same four cost correction factors as given in Module 2 for the distribution pipeline, in order to account for differing levels of urbanization, existing utilities in rights-of-way, and resurfacing requirements for rights-of-way. The program assumes that transmission pipeline is directly buried in soil that does not require drilling or blasting, and that pavement must be removed and replaced for trenching.

ENTER GEOTHERMAL INJECTION PIPELINE RIGHT-OF-WAY DISTANCE FROM  
THE CENTRAL HEAT EXCHANGE FACILITY TO THE INJECTION SITE. SELECT  
INSTALLATION COST CORRECTION FACTOR.

This input accounts for returning the geothermal fluids to an injection site, which may or may not be coterminous with the geothermal production site, depending upon local geological and/or hydrological conditions. Installation cost correction factors are again applied in order to account for conditions along the route of the injection pipeline.

THE GEOTHERMAL SUPPLY AND RETURN TRANSMISSION PIPELINE CAPITAL  
COST IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the program's summation of the geothermal

transmission pipeline capital costs, based on the distances and installation cost correction factors selected above.

PUMPING HEAD IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the program's estimate of pumping head necessary to withdraw geothermal fluids from production wells, circulate them to the central heat exchange facility, and, if applicable, return them to injection wells.

THE PROGRAM ASSUMES A PUMP EFFICIENCY OF 70%. ENTER OVERRIDE IF DESIRED.

As with the distribution pipe's circulation pumps, this step accounts for typical pump efficiencies using a default value of 70%.

THE GEOTHERMAL PUMP CAPITAL COST IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the estimated capital costs for the pumps required to produce and circulate geothermal fluids from wells to the central heat exchange facility, and, if applicable, to return them to injection wells.

THE TOTAL CAPITAL COST FOR THE GEOTHERMAL SYSTEM IS \_\_\_\_\_.  
ENTER OVERRIDE IF DESIRED.

This is the program's summation of all geothermal capital costs estimated thus far.

THE INITIAL GEOTHERMAL SYSTEM OPERATION AND MAINTENANCE COST IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the program's estimate of geothermal operation and maintenance costs, including electricity consumed for pumping, and maintenance of wells and pipelines.

In cases where biomass or waste heat are selected as the system's heat source, the following series of steps appear in place of the foregoing geothermal steps. The steps for biomass and waste heat are identical, and in the interests of brevity they are reproduced below in a joint format, whereas only one of the two would actually appear during a single program run.

ENTER TEMPERATURE OF BIOMASS/WASTE HEAT SOURCE.

ENTER PEAK HEAT AVAILABLE FROM BIOMASS/WASTE SOURCE IN BTU/HR.

ENTER ANNUAL HEAT AVAILABLE FROM BIOMASS/WASTE SOURCE IN BTU/HR.

ENTER ANNUAL HEAT AVAILABLE FROM BIOMASS/WASTE SOURCE IN BTU/YR.

The user enters this data in order to characterize the heat quality and quantity for either biomass or waste heat sources. This information should be obtained from the

operator of the source, e.g. an industry which has waste heat available at its plant.

ENTER PERCENTAGE OF PEAK BIOMASS/WASTE HEAT AVAILABLE BY MONTH. EACH OF THE 12 VALUES MUST BE LESS THAN OR EQUAL TO 1.0, AND AT LEAST ONE VALUE MUST EQUAL 1.0.

These entries characterize the time-based availability of the biomass/waste source for comparison against the service area's peak demand calculated in Module 2. Again, these values should be obtained from the operator of the biomass/waste heat source.

ENTER PERCENTAGE OF ANNUAL HEAT AVAILABLE BY MONTH. THE 12 VALUES ENTERED MUST SUM TO 1.0.

This is similar to the foregoing step, except that it represents the time-based availability of annual heat from the biomass/waste source, for comparison against the annual load duration curve generated at the beginning of Module 3. These values should also be obtained from the operator of the biomass/waste heat source. In effect, this and the foregoing step are used to determine whether the biomass/waste heat is sufficient to meet the system's demands with or without the assistance of a conventionally-fueled peaking boiler. The need for such a boiler is addressed at the end of Module 3.

ENTER THE COST, IF ANY, FOR THE BIOMASS/WASTE HEAT AT ITS SOURCE IN DOLLARS PER MILLION BTU.

This entry accounts for any cost levied to the district heating system for obtaining the biomass/waste from its source. Users should consult with operators of such sources to determine appropriate values for this input.

THE CAPITAL COST FOR A BIOMASS BOILER/WASTE HEAT EXCHANGER IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This step estimates the capital cost for a boiler to be installed at a biomass site for combustion of the biomass; or installation of a heat exchanger to recover waste heat at its source. The user may override this estimate if a boiler or heat exchanger is already in place at the source.

ENTER DISTANCE FROM BIOMASS/WASTE HEAT SOURCE TO THE CENTRAL HEAT EXCHANGE FACILITY.

This is a step similar to the geothermal transmission pipeline calculation, and should be measured in terms of the right-of-way route that a pipeline would follow from the biomass/waste heat site to the central heat exchange facility. See Appendix J for a discussion of transmission pipeline routing.

ENTER BIOMASS/WASTE HEAT TRANSMISSION PIPELINE INSTALLATION COST  
CORRECTION FACTOR.

This is the same type of pipeline cost correction factor  
used previously in the distribution and geothermal cases,  
and is intended to account for construction conditions along  
the route of a transmission pipeline from the biomass/waste  
heat site to the central heat exchange facility.

THE CAPITAL COST OF THE BIOMASS/WASTE HEAT TRANSMISSION PIPELINE  
IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

Based on the pipeline distance and installation cost  
correction factor entered above, this step estimates the  
capital cost of a supply and return transmission line from  
the biomass/waste heat to the central heat exchange  
facility. It is assumed that domestic/municipal water is  
circulated in this pipeline for purposes of conveying the  
biomass/waste heat.

THE TOTAL CAPITAL COST FOR THE BIOMASS/WASTE HEAT SYSTEM IS  
ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the program's summation of all capital costs  
estimated thus far for the biomass heat source.



SELECT CONVENTIONAL PEAKING BOILER TYPE: ELECTRIC OR FOSSIL FUEL.

In cases where a conventional peaking boiler is being used, the user is allowed to select either electricity or fossil fuel for its operation.

THE CAPITAL COST OF A CONVENTIONAL PEAKING BOILER IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This step estimates the capital cost for a conventional peaking boiler to either meet the percentage of peak load not met by geothermal resources in a geothermal case; or to eliminate a heat deficit or reduce a heat surplus in either biomass or waste heat cases.

THE COST OF CONVENTIONAL PEAKING FUEL IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This step calculates the cost of operating the conventional peaking boiler. If an electrical boiler was selected the program automatically displays the cost of electricity expressed in dollars per million Btu. If a fossil-fueled boiler was selected the user must enter the purchased cost of the fossil fuel, e.g. natural gas or fuel oil, in dollars to million Btu. See Appendix C for a discussion of fuel prices and conversions to dollars per million Btu.

THE ITEMS BELOW ARE FOR BOTH DISTRIBUTION AND HEAT SOURCE COMPONENTS OF THE DISTRICT HEATING SYSTEM.

This statement appears at this point in order to clarify for the user that the remainder of the items in this Module represent a combination of cost factors for both the distribution (Module 2) and heat source (Module 3) components of the district heating system.

THE PROGRAM ASSUMES 20% OF THE CAPITAL COST AS ALLOWANCE FOR ENGINEERING AND CONTINGENCIES FOR THE PROJECT. ENTER OVERRIDE IF DESIRED.

This item accounts for costs that will be incurred for engineering design services in a project, along with an adequate contingency budget for unforeseen occurrences during project construction.

THE TOTAL CAPITAL COST OF THE SYSTEM IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the program's summation of all capital costs estimated thus far in Modules 2 and 3.

THE SYSTEM'S TOTAL INITIAL OPERATION AND MAINTENANCE COST IS ESTIMATED TO BE \_\_\_\_\_. ENTER OVERRIDE IF DESIRED.

This is the program's summation of all initial operating and maintenance costs estimated thus far in Modules 2 and 3.

## Module 4

This Module estimates the system's life-cycle costs, along with each study area's favorability for district heating. The program assumes the following conditions for life-cycle costing, which are purposely intended to present a conservative economic picture: one construction year; no interest income during construction, nor hook-up fee income during operations. For private taxable scenarios the program assumes the following: a depreciable asset value of 95% of capital costs, all of which is considered eligible for accelerated cost recovery over five years; and availability of the 10% federal business investment tax credit on all project costs, except, where applicable, intangible geothermal drilling costs; and all transactions are assumed to occur on December 31 of each year.

PRINT OR DO NOT PRINT OUTPUT TO LINE PRINTER.

This is the same option offered at the beginning of each previous Module.

ENTER COMMUNITY NAME. ENTER DATE. ENTER SERVICE AREA NAME.  
ENTER CASE NAME.

These are the same data file identifiers used previously in Modules 2 and 3.

ENTER GENERAL ECONOMIC INFLATION RATE FOR THE PROJECT'S FIRST 5 YEARS, AND ALL REMAINING YEARS.

This entry allows the user to input a two-tiered inflation estimate that is used in the program's life-cycle costing to escalate costs for all items other than electricity conventional fuels, and biomass or waste heat costs.

ENTER ELECTRICITY COST INFLATION RATE FOR THE PROJECT'S FIRST 5 YEARS, AND ALL REMAINING YEARS THEREAFTER.

This is a similar two-tiered inflation input that is used to escalate electricity costs. Projected electricity inflation rates for Washington are described in Appendix C.

ENTER COST INFLATION RATE FOR CONVENTIONAL PEAKING FUEL FOR THE PROJECT'S FIRST 5 YEARS, AND ALL REMAINING YEARS THEREAFTER.

This is a similar inflation estimate that is provided in the event the user selected a fossil-fueled conventional peaking boiler rather than an electrical-fired boiler. In cases where an electrical-fired boiler was chosen the user should simply repeat the electrical inflation rates entered above. Fossil fuel inflation estimates for Washington are given in Appendix C.

ENTER COST INFLATION RATE FOR BIOMASS OR WASTE HEAT SOURCE COST FOR THE PROJECT'S FIRST 5 YEARS, AND ALL REMAINING YEARS THEREAFTER.

This is a similar inflation estimate provided in biomass or waste heat cases, to allow the user to inflate the cost charged by the source's operator.

SYSTEM OWNERSHIP IS: PUBLIC OR PRIVATE.

This selection allows the user to simulate either public ownership without taxes and profit, or alternatively, private ownership where taxes and profit must be taken into account. This choice results in two different sets of queries below which are denoted between public and private.

ENTER PERCENTAGE OF CAPITAL COST FOR INSURANCE, AND INSURANCE INFLATION RATE FOR THE PROJECT'S FIRST 5 YEARS, AND ALL REMAINING YEARS THEREAFTER.

This step accounts for the cost of insurance on the project's facilities. Generally, this cost will range from 1-2% of capital costs, with insurance inflation rates several percentage points beneath the general economic rate specified above.

The following six steps are given if private ownership was selected above.

ENTER PERCENT OF CAPITAL COST FOR PROPERTY TAXES, AND INFLATION RATE FOR PROPERTY TAXES DURING THE PROJECT'S FIRST 5 YEARS, AND ALL REMAINING YEARS THEREAFTER.

This item accounts for the cost of local property taxes, and their expected inflation rate over the project's life. The user should consult with local tax officials to determine an appropriate percentage of capital cost to be entered, and appropriate inflation rates.

ENTER COMBINED RATE OF FEDERAL AND STATE INCOME TAXES.

This item accounts for a private operator's payment of federal and state income taxes. The maximum rate is approximately 48%, but many private companies have an actual rate considerably less than the maximum as a result of various reductions in their tax liabilities.

ENTER REQUIRED RATE OF RETURN ON EQUITY.

This step accounts for the profit required by a private operator.

ARE ALTERNATE ENERGY TAX INCENTIVES APPLICABLE? IF GEOTHERMAL, ENTER PERCENT OF DISTRICT HEAT SALES ATTRIBUTED TO GEOTHERMAL WELLHEAD OPERATIONS, AND PERCENT OF WELL COST THAT IS INTANGIBLE.

While the program automatically takes a standard federal business investment tax credit of 10% for private owners,

this option allows the user to also utilize federal alternate energy tax benefits that include an energy tax credit, and if geothermal is being used, intangible drilling cost deductions and depletion allowance. In biomass and waste heat cases a 10% energy tax credit is possible. In geothermal cases a 15% energy tax credit is possible, along with a 15% depletion allowance on wellhead operations (which allows a 15% reduction in wellhead revenues before taxes), and a complete deduction of all intangible drilling expenses in the year in which they occur. Geothermal tax incentives are only available for resources above 121oF, and if a resource temperature was entered in Module 3 beneath that temperature this option does not appear in Module 4. If the resource temperature is above 121oF, and the user selects the tax incentives, the percent of district heat sales price attributable to wellhead operations can be obtained by comparing geothermal costs estimated previously against total system costs. The percent of well costs that are intangible generally range from 60 to 80%. It is stressed that, as of this writing (July, 1984), the status of federal alternate energy tax incentives is uncertain, with a possibility that they will be unavailable in the coming years. Users should consult with knowledgeable tax professionals before using these program options.

At this point the program sequence merges without further distinction between public or private ownership, with the following items applying to both cases.

THE TOTAL CAPITAL COST FOR THE SYSTEM IS \_\_\_\_\_. ENTER THE AMOUNT TO BE DEBT FINANCED.

This step allows the user to establish the equity and debt structure for the project by indicating the amount of money to be borrowed for project construction. As a general rule, public entities usually borrow 100% of project capital costs, and private entities may borrow up to approximately 80% of capital costs. The most conservative economic picture will be given if no debt, or 100% equity, is used. Zero percent debt should be used as a base condition when comparing different project scenarios to avoid mixing the "leveraging" effects on project cash flow that result from heavy debt financing.

ENTER INTEREST RATE ON DEBT.

In cases where debt financing is used this entry accounts for the interest rate to be charged on the loan. This should be the most recent prevailing rate for the intended debt instrument, e.g. a municipal bond rate versus the prime commercial loan rate.

ENTER PROPOSED DISTRICT HEAT SALES PRICE IN DOLLARS PER MILLION BTU.

This is the user's last input, and represents one of the program's major results in that it constitutes the competitiveness of the district heating system versus other

fuels already available in the community. Upon entry of this value the program automatically performs a life-cycle cost analysis to determine if the price is sufficient to either break-even in a publicly-owned scenario, or obtain the specified profit in a privately-owned scenario. If the user enters a sales price which is insufficient under these terms the program displays the negative cumulative discounted cash flow that results from the insufficient price, and allows the user to reenter a higher price. If the value entered is sufficient to produce a positive cumulative discounted cash flow the program prints the resulting life-cycle income and cash flow statements, and the final district heating favorability ratings for each of the study areas that were combined into a common service area in Module 2.

### 3. GLOSSARY OF PROGRAM TERMS

ACTLD	load factor for actual load data, as a decimal
ADJHD	pumping head adjusted for artesian pressure, in feet
ANPER	percentage of total annual service area load to be met monthly, as a decimal
ANSHT	annual space heating load for a particular BLDGTYPE, in Btu/yr
APAS	actual annual industrial process load in study area, in Btu/yr
APHS	actual peak industrial process load in study area, in Btu/hr
ARTHD	geothermal artesian head, in feet
ASAS	actual annual space heating load in study area, in Btu/yr
ASHS	actual peak space load in study area, in Btu/hr

AT	total gross land area of service area, in acres
ATAS	actual total annual load (space, water, and process) in study area, in Btu/yr
ATHS	actual total peak (space, water, and process) in study area, in Btu/hr
ATP	geothermal artesian pressure at wellhead, in psi
AWAS	actual annual water heating load in study area, in Btu/yr
AWHS	actual average hourly water heating load in study area, in Btu/hr
BAN	annual heat available from biomass source, in Btu/yr
BAP	percent of biomass annual heat available by month, as a decimal
BBOIL	capital cost of biomass boiler adjusted for installation and contingencies, in million \$
BCCST	total capital cost of biomass system, in million \$

BCST	heat cost charged by supplier of biomass heat, in \$MMBtu
BDIFF	difference between service area load and available biomass heat
BDIST	distance from biomass source to CENFACILITY, in miles
BEF	efficiency of conventional peaking boiler, as a decimal
BGPM	biomass transmission pipeline flow rate, in gpm
BINFA	biomass inflation rate for first 5 years of project life, as a decimal
BINFB	biomass inflation rate for remaining years of project life, as a decimal
BIO	biomass heat source
BIOOM	total initial operation and maintenance cost for biomass system, in million \$/yr
BOILER	biomass boiler capital cost in million \$

BPCST	capital cost of biomass transmission pipeline, in million \$
BPIPK	biomass transmission pipeline installation cost correction factor
BPK	peak heat available from biomass source, in Btu/hr
BPP	percent of biomass peak heat available by month, as a decimal
BPR	study area non-diversified peak space load for residential building, in Btu/hr
BT	one of nine types of buildings
BTEMP	temperature of biomass heat source, in OF
CBLDG	capital cost of central heat exchanger and control building, in million \$
CCS	central heat exchanger and control system capital cost, in million \$ (includes heat pump if heat source <120OF)
CDO	initial distribution system maintenance costs, in million \$/yr

CENF	total capital cost of CNTRL and CBLDG, in million \$
CHE	first year electrical costs for heat pump, in million \$/yr
CKW	electric cost, in \$/kwh
CNTRL	capital cost of central control system adjusted for electrical work and contingencies, in million \$
COMPINT	compounded inflation rate from 1983 to date, as a decimal
CONSVHIGH	conservation factor for buildings constructed prior to 1955
CONSVLOW	conservation factor for buildings constructed after 1975
CONSVMEAN	conservation factor for buildings constructed between 1955-1975
CPDIST	capital cost of distribution pumps, in million \$

CPE                    first year cost of electricity for geothermal  
                         production pumping, in million \$/yr

CPF                    cost of conventional peaking boiler fuel, in  
                         \$/MBtu

CUMMS                cumulative market share for district heating in  
                         service area, as a decimal

CZN                    range of annual heating degree days from U.S.DOE  
                         Building Energy Performance data

D                      mean annual heating degree days for a given CZN

DD                    annual heating degree days, in °F

DEBT                 amount of total capital costs to be debt  
                         financed, in million \$

DELTATEE            difference between 68°F and outside design  
                         temperature, in °F

DEPR                 depreciation, as a decimal

DEPTH                unadjusted geothermal production zone depth, in  
                         feet

DIAM	diameter of distribution pipeline
DISTC	total capital cost for distribution system, in million \$
DISTP	distribution pipe installation costs correction factor, as a decimal
DISTR	distribution system return temperature, in OF
DPL	geothermal depletion allowance, as a decimal
DRILL	unadjusted production well drilling cost, in average \$/ft
DRHOL	number of unsuccessful geothermal wells
DSTOM	total initial operation and maintenance cost for distribution system, in million \$/yr
DT	usable amount of heat or drop in temperature across heat exchanger, in degrees Fahrenheit
DV	peak load diversity factor, as a decimal
EER	electricity inflation rate, as a decimal

EINFA	electricity inflation rate for first 5 years of project life, as a decimal
EINFB	electricity inflation rate for remaining years of project life, as a decimal
EIR	economic inflation rate, as a decimal
ENG	percentage of system capital cost allowed for engineering and contingency, as a decimal
ETC	federal energy tax credit for biomass and waste heat, as a decimal
ETCBW	federal energy tax credit for biomass or waste heat, as a decimal
ETCG	federal energy tax credit for geothermal, as a decimal
EXLND	cost of geothermal exploration and land acquisition, in million \$
FLOW	unadjusted maximum flow rate, in gpm
FS	study area district heating favorability ratio
FYS	annual heat sales, in MBtu/yr

GAS	study area gross land area, in acres
GCCST	total capital cost of geothermal system, in million \$
GDAS	gross density of annual thermal use in study area, in MBtu/acre/year
GDEPTH	geothermal production zone depth below ground surface, in feet, adjusted for reliability
GDIST	transmission pipeline distance from most favorable geothermal resource site to most favorable load area, in miles
GDRDN	geothermal production well draw down, in feet
GDRIL	production well drilling cost, in \$/ft, adjusted for reliability
GEO	geothermal heat source
GEODRAWDOWN	geothermal production well drawdown, in feet
GEODT	usable geothermal heat, in OF

GEOOM	total initial operation and maintenance costs of geothermal system, in million \$/yr
GFLOW	geothermal production well flow rate adjusted for reliability, in gpm
GFRAC	percentage of system peak load to be met by geothermal, as a decimal
GINFA	general economic inflation rate for first 5 years of project life, as a decimal
GINFB	general economic inflation rate for remaining years of project life, as a decimal
GLF	geothermal load factor for service area, as a decimal
GPCST	total capital cost of geothermal transmission (supply and return) pipeline, in million \$
GPEF	geothermal wellhead pump efficiency, as a decimal
GPIPK	geothermal transmission pipeline installation costs correction factor

GPM	distribution pipeline flow rate, in gallons per minute
GPPOW	geothermal wellhead pump power, in horsepower
GRCST	capital cost of geothermal return transmission pipeline, in million \$
GSCST	capital cost of geothermal supply transmission pipeline, in million \$
GSTAT	static water level below ground level, in feet, adjusted for reliability
GTEMP	geothermal production wellhead temperature, in degrees Fahrenheit, adjusted for reliability
GW CST	total capital cost of geothermal well over project life, in million \$
H	pumping head, in feet
HD	distribution system piping head, in feet
HEAD	geothermal pumping head, in feet

HEATLOSS	percent of heat lost in distribution, as a decimal
HI	conversion of COMPINT for updating capital cost coefficients
IINFA	insurance inflation rate for first 5 years of project life, as a decimal
IINFB	insurance inflation rate for remaining years of project life, as a decimal
IJDIST	geothermal injection transmission pipeline distance, in miles
IJWEL	total number of geothermal injection wells required for service area
INS	percent of capital cost for insurance, as a decimal
INTRT	interest rate on debt, as a decimal
IP	weighted average initial market penetration rate for service area, as a decimal

JA                    total annual service area load adjusted for  
                     ultimate market penetration, in Btu/yr

JAX                   gross annual service area load unadjusted for  
                     market penetration, in Btu/yr

JAY                   gross annual service area load adjusted for  
                     initial market penetration, in Btu/yr

JP                    gross diversified peak service area load  
                     adjusted for ultimate market penetration, in  
                     Btu/hr

JPG                   geothermal portion of gross diversified peak for  
                     service area adjusted for ultimate market  
                     penetration, in Btu/hr

LD                    length of distribution pipeline, in feet

LF                    study area load factor, as a decimal

LIFE                   length of district heating system useful life,  
                     in years

MS                    minimum annual sales required for service area  
                     operations, in MBtu/yr

MSA	minimum first year heat sales per land area for successful service area operations, in MBtu/acre/yr
MSB	service area market share for district heating in the second year (first year of sales), as a decimal
NDAS	net density of annual thermal use in study area at end of project life, in MBtu/acre/yr
PBCST	capital cost of conventional peaking boiler, in million \$
PBMNT	conventional peaking boiler maintenance cost, in million \$/yr
PBOIL	type of conventional peaking boiler
PBOM	conventional peaking boiler total operation and maintenance cost, in million \$/yr
PDIST	conversion of gpm and lift in feet into horsepower at PUMEF
PFCST	conventional peaking fuel cost, in \$/MBtu

PGR                    annual market penetration growth rate over the project's sales life, as a decimal

PINFA                peaking fuel inflation rate for first 5 years of project life, as a decimal

PINFB                peaking fuel inflation rate for remaining years of project life, as a decimal

PIR                   peaking fuel cost inflation rate, as a decimal

PK                    peak space heating load for a particular BLDGTYPE, in Btu/hr

PKFRAC              percentage of peak load to be met by conventional boiler, as a decimal

PRIVATE             privately owned system

PSP                   direct heat sales price, in \$/MBtu

PTDS                 diversified peak thermal load density for study area, in Btu/hr/acre (followed by area number)

PTX                   percent of capital cost for property tax, as a decimal

PUBLIC	Publicly owned system
PUCST	geothermal wellhead pump capital cost, in million \$
PUMEF	distribution pump efficiency, as a decimal
PWEL	number of geothermal production wells
RL	geothermal resource data reliability value
ROR	required rate of return on equity, as a decimal
RPWEL	number of replacement geothermal wells
SCCST	total capital cost for heat source and distribution system, in million \$
SMOM	total initial operation and maintenance cost for heat source and distribution system, in million \$/yr
STATIC	unadjusted geothermal production well static water level, in feet
SYSOWN	system ownership as public or private

TAP	total annual payment on debt including principal and interest, in million \$
TD	assumed distribution system fluid send-out temperature, in OF
TDHS	total diversified peak load in study area, in Btu/hr
TEMP	unadjusted geothermal wellhead temperature, in degrees Fahrenheit
TIAS	total initially penetrated annual load for study area, in Btu/yr
TINFA	property tax inflation rate for first 5 years of project life, as a decimal
TINFB	insurance inflation rate for remaining years of project life, as a decimal
TLHS	total gross study area peak, including diversification factor and distribution losses, in Btu/hr
TOTAW	sum of study area annual water heating load for all BLDGTYPE's, in Btu/yr

TOTPEAKWTR	total study area peak water heat load, in Btu/hr
TOTPH	total study area peak space heating load, in Btu/hr
TTAS	total annual residential, commercial, and institutional load in study area, in Btu/yr
TTHS	total non-diversified peak load in study area (excluding average hourly water heating), in Btu/hr
TUAS	total ultimately penetrated annual load for study area, in Btu/yr
TUHS	total ultimately penetrated peak load for study area, in Btu/hr
TW	outside design temperature in degrees Fahrenheit
TWHS	total average hourly water heating load in study area, in Btu/hr
TXRT	combined rate of federal and state income taxes, as a decimal

UP	weighted average ultimate market penetration rate for service area, as a decimal
UPB	unpaid principal balance on debt
UPS	study area ultimate market penetration rate, as a decimal
VPUB	cumulative discounted cash flow for public system, in \$
VPVT	cumulative discounted cash flow for private system, in \$
WAN	annual heat available from waste heat source, in Btu/yr
WAP	percentage of annual waste heat available by month, as a decimal
WASTE	waste heat source
WASTEOM	total initial operation and maintenance cost for waste heat system, in million \$
WCCST	total capital cost of waste heat system, in million \$

WCST	heat price charged by water heat supplier, in \$/MBtu
WDIFF	difference between service area load and available waste heat
WDIST	distance from waste heat source to central heat exchange facility, in miles
WELOP	maximum energy output per production well, in Btu/hr
WEXCH	waste heat exchanger capital cost, in million \$
WEXCHCST	capital cost of WESCH adjusted for installation and contingencies, in million \$
WGM	waste heat transmission pipeline flow rate, in gpm
WH	annual water heating load for a particular BLDGTYPE, in Btu/yr
WHD	percent of distribt heat sales price attributed to geothermal wellhead operations, as a decimal

WINFA	waste heat inflation rate for first 5 years of project life, as a decimal
WINFB	waste heat inflation rate for remaining years of project life, as a decimal
WP	total number of geothermal production wells required for service area
WPCST	capital cost of waste heat transmission pipeline, in million \$
WPIPK	waste heat transmission pipeline installation cost correction factor
WPK	peak heat available from waste heat source, in Btu/hr
WPP	percent of peak waste heat available in a given month, as a decimal
WTEMP	waste heat temperature, in °F

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## 5. APPENDICES

## Appendix A

### SAMPLE PROGRAM OUTPUT

In order to assist users in familiarizing themselves with the program's format and content, the following pages are actual photocopies of sample program output for a fictitious community. The program run which has been illustrated by this sample output includes three study areas in Module 1, which are combined into a common service area in Module 2. This is followed by a geothermal heat source case from Modules 3 and 4, assuming public ownership of the system; and a subsequent Module 3 and 4 run using a biomass heat source under private system ownership.

BEGIN MOD1

Enter community name: HEATVILLE

1) Modifying existing community

2) Beginning new community

Select a number: 2

Enter date in MM/DD/YY format: 07/02/84

Enter compound inflation rate (COMPINT)

from 1983 to date as a decimal: .05

Enter local annual heating degree days (DD): 5900

Enter winter outside design temperature (TW) in degrees F: 9

HEATVILLE  
07/02/84  
MOD1

Enter study area number: 1  
Enter study area gross land area (GAS) in acres: 70

1)Actual load data is available for study area.  
2)Actual load data is NOT available for study area.  
Select a number: 2

Enter total square footage for buildings in the study area exclusive of any buildings for which actual load values were entered above. Enter footage according to date of construction categories of HIGH consumption (before 1955), MEAN consumption (1955-1975), or LOW consumption (after 1975):

		Enter Total Square Feet by Year of Construction		
		<1955	1955-75	>1975
Single-family	(BLDGTYPE 1)	10594	26743	112726
Multi-family	(BLDGTYPE 2)	0	18000	0
Mobile home	(BLDGTYPE 3)	0	0	0
Hotel/motel	(BLDGTYPE 4)	0	0	0
Office	(BLDGTYPE 5)	0	0	0
Retail	(BLDGTYPE 6)	0	5800	0
Restaurant	(BLDGTYPE 7)	0	0	0
Public assembly	(BLDGTYPE 8)	0	0	0
Warehouse	(BLDGTYPE 9)	0	0	0

The program uses a typical peak load diversity factor (DV) of 0.7. Enter an override value for DV if desired, as a decimal:

The program assumes a typical distribution heat loss in district heating (HLOSS) of 5% (0.05). Enter override value for HLOSS if desired, as a decimal:

Enter initial market penetration rate (IPS) and ultimate market penetration rate (UPS) expected for district heating in the study area, as decimals:

IPS = .5  
UPS = .95

Processing of Study Area # 1 is complete.

Total diversified peak (TDHS) in Btu/hr = 12586500  
Total div peak with dist loss (TLHS) in Btu/hr = 13215800  
Total annual without pen adj (TTAS) in Btu/yr = 17299200000  
Div peak density (PTDS) in Btu/hr/ac = 188798  
Load factor (LFS) = .149427  
Gross annual density (GDAS) in MBtu/yr/ac = 247.132

HEATVILLE  
07/02/84  
MOD1

Net annual density (NDAS) in MBtu/yr/ac = 234.775  
Total pen peak (TUHS) in Btu/hr = 12555000  
Total ult pen annual (TUAS) in Btu/yr = 16434300000  
Total int pen annual (TIAS) in Btu/yr = 8649620000

Do you want to print all study area variables?

1) Yes

2) No

Select a number: 2

1) Process additional study areas

2) Return to main menu

Select a number: 1

HEATVILLE  
07/02/84  
MOD1

Enter study area number: 2  
Enter study area gross land area (GAS) in acres: 12

1) Actual load data is available for study area.  
2) Actual load data is NOT available for study area.  
Select a number: 2

Enter total square footage for buildings in the study area exclusive of any buildings for which actual load values were entered above. Enter footage according to date of construction categories of HIGH consumption (before 1955), MEAN consumption (1955-1975), or LOW consumption (after 1975):

		Enter Total Square Feet by Year of Construction		
		<1955	1955-75	>1975
Single-family	(BLDGTYPE 1)	0	0	0
Multi-family	(BLDGTYPE 2)	0	0	0
Mobile home	(BLDGTYPE 3)	0	0	0
Hotel/motel	(BLDGTYPE 4)	0	0	197500
Office	(BLDGTYPE 5)	0	0	0
Retail	(BLDGTYPE 6)	0	0	10000
Restaurant	(BLDGTYPE 7)	0	0	12000
Public assembly	(BLDGTYPE 8)	0	0	0
Warehouse	(BLDGTYPE 9)	0	0	0

The program uses a typical peak load diversity factor (DV) of 0.7. Enter an override value for DV if desired, as a decimal: .9

The program assumes a typical distribution heat loss in district heating (HLOSS) of 5% (0.05). Enter override value for HLOSS if desired, as a decimal:

Enter initial market penetration rate (IPS) and ultimate market penetration rate (UPS) expected for district heating in the study area, as decimals:

IPS = .9

UPS = 1

Processing of Study Area # 2 is complete.

Total diversified peak (TDHS) in Btu/hr = 6617660  
Total div peak with dist loss (TLHS) in Btu/hr = 6948550  
Total annual without pen adj (TTAS) in Btu/yr = 4465750000  
Div peak density (PTDS) in Btu/hr/ac = 579046  
Load factor (LFS) = .073366  
Gross annual density (GDAS) in MBtu/yr/ac = 372.146

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MOD1

Net annual density (NDAS) in MBtu/yr/ac = 372.146  
Total pen peak (TUHS) in Btu/hr = 6948550  
Total ult pen annual (TUAS) in Btu/yr = 4465750000  
Total int pen annual (TIAS) in Btu/yr = 4019180000

Do you want to print all study area variables?

1)Yes

2)No

Select a number: 2

1) Process additional study areas

2) Return to main menu

Select a number: 1

Enter study area number: 3

Study area # 3 has been initialized

1) Reenter data for study area# 3

2) Begin a new study area

Select a number: 1

Enter study area gross land area (GAS) in acres: 5

1) Actual load data is available for study area.

2) Actual load data is NOT available for study area.

Select a number: 1

Enter any actual heating load data available for study area as follows (press [RETURN] if data is unavailable).

Actual annual space heating (ASAS) in BTU/yr:

Actual annual water heating (AWAS) in BTU/yr:

Actual peak industrial process load (APHS) in BTU/hr: 4600000

Actual annual industrial process load (APAS) in BTU/yr: 6300000000

The program assumes an actual space heating load factor (ACTLD) of 0.25

Enter override value for ACTLD if desired as a decimal:

Enter total square footage for buildings in the study area exclusive of any buildings for which actual load values were entered above. Enter footage according to date of construction categories of HIGH consumption (before 1955), MEAN consumption (1955-1975), or LOW consumption (after 1975):

Enter Total Square Feet  
by Year of Construction

<1955                  1955-75                  >1975

Single-family	(BLDGTYPE 1)	0	0	0
Multi-family	(BLDGTYPE 2)	0	0	0
Mobile home	(BLDGTYPE 3)	0	0	0
Hotel/motel	(BLDGTYPE 4)	0	0	0
Office	(BLDGTYPE 5)	4700	0	0
Retail	(BLDGTYPE 6)	0	0	0
Restaurant	(BLDGTYPE 7)	0	0	0
Public assembly	(BLDGTYPE 8)	0	0	0
Warehouse	(BLDGTYPE 9)	8398	0	0

The program uses a typical peak load diversity factor (DV) of 0.7. Enter an override value for DV if desired, as a decimal: .95

The program assumes a typical distribution heat loss in

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MOD1

district heating (HLOSS) of 5% (0.05). Enter override value for HLOSS if desired, as a decimal:

Enter initial market penetration rate (IPS) and ultimate market penetration rate (UPS) expected for district heating in the study area, as decimals:

IPS = .8  
UPS = 1

Processing of Study Area # 3 is complete.

Total diversified peak (TDHS) in Btu/hr = 5217980  
Total div peak with dist loss (TLHS) in Btu/hr = 5478870  
Total annual without pen adj (TTAS) in Btu/yr = 7061850000  
Div peak density (PTDS) in Btu/hr/ac = 1095770  
Load factor (LFS) = .147137  
Gross annual density (GDAS) in MBtu/yr/ac = 1412.37  
Net annual density (NDAS) in MBtu/yr/ac = 1412.37  
Total pen peak (TUHS) in Btu/hr = 5478870  
Total ult pen annual (TUAS) in Btu/yr = 7061850000  
Total int pen annual (TIAS) in Btu/yr = 5649480000

Do you want to print all study area variables?

- 1) Yes
- 2) No

Select a number: 2

- 1) Process additional study areas
- 2) Return to main menu

Select a number: 2

BEGIN MOD2

Enter community name: HEATVILLE

Enter date in MM/DD/YY format: 07/02/84

Enter service area name: CENTRAL

Enter case name: SAMPLE

Enter number of subcases to be evaluated when offered as  
an option for user inputs: 2

Study areas which have been loaded are:

1 2 3

Enter study area numbers to be included in  
service area and type 'COMPLETE' when all numbers are entered

1

2

3

COMPLETE

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE  
07/02/84  
MOD2

The total diversified peak load for the service area adjusted for ultimate market penetration(JP) is estimated to be 24982400 Btu/hr.  
Enter override value for JP if desired, in Btu/hr:

The total annual load for the service area adjusted for ultimate market penetration (JA) is estimated to be 27961900000 Btu/yr.  
Enter override value for JA if desired, in BTU/yr:

The initial district heating market share(MSB) is .655116  
Enter override for MSB, if desired, as a decimal:

Enter length of project life (LIFE) from 10 to 25 years: 25

If desired, enter override market share expected for district heating in the service area for each year of the project's operating life:

Subcase # 1

Year(LIFE)	Assumed Market Share	Enter Override as a decimal
1	Construction	Construction
2	.655116	.655116
3	.004788	.004788
4	.007881	.007881
5	.010827	.010827
6	.013572	.013572
7	.016064	.016064
8	.018256	.018256
9	.020109	.020109
10	.021587	.021587
11	.022662	.022662
12	.023316	.023316
13	.023535	.023535
14	.023316	.023316
15	.022663	.022663
16	.021587	.021587
17	.020109	.020109
18	.018257	.018257
19	.016064	.016064
20	.013572	.013572
21	.010828	.010828
22	.007881	.007881
23	.004788	.004788
24	.001606	.001606
25	.001606	.001606

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE  
07/02/84  
MOD2

Subcase # 2

Year(LIFE)	Assumed Market Share	Enter Override as a decimal
1	Construction	Construction
2	.655116	.655116
3	.004788	.004788
4	.007881	.007881
5	.010827	.010827
6	.013572	.013572
7	.016064	.016064
8	.018256	.018256
9	.020109	.020109
10	.021587	.021587
11	.022662	.022662
12	.023316	.023316
13	.023535	.023535
14	.023316	.023316
15	.022663	.022663
16	.021587	.021587
17	.020109	.020109
18	.018257	.018257
19	.016064	.016064
20	.013572	.013572
21	.010828	.010828
22	.007881	.007881
23	.004788	.004788
24	.001606	.001606
25	.001606	.001606

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE  
07/02/84  
MOD2

The total gross acreage of the service area (AT) is estimated to be 87 acres.

Enter override value for AT if desired, in acres:

Select distribution pipeline installation cost correction factor (DISTPIPEK) from the following:  
1.0 for highly urbanized service area with uncertain existing utility locations in rights-of-way;  
0.75 for highly urbanized service area with known utility locations in rights-of-way;  
0.50 for moderately urbanized service area;  
0.35 for sparsely urbanized service area.

Enter selected DISTP: .5

Enter distribution fluid send-out temperature(TD) from 95 to 210 degrees Fahrenheit:

1:120 2: 120

The program assumes a 75 degree distribution loop return temperature (DISTR). Enter override value for DISTR if desired, in degrees Fahrenheit:

1: 75 2: 75

The program calculates the distribution pipeline length(LD) to be 7786.88 feet. Enter override value for LD if desired, in feet:

1: 7786.88 2:6100

Pumping head (HD) is estimated to be, in feet:

1: 233.607 2: 183

Enter override value for HD if desired, in feet:

1: 233.607 2: 183

The program assumes a distribution pump efficiency (PUMEF) of 70%. Enter override for PUMEF if desired, as a decimal:

The distribution pump capital cost (CPDIST) is estimated to be (in million \$):

1: .037447 2: .029335

Enter override value for CPDIST if desired, in million \$:

1: .037447 2: .029335

The program estimates the cost of a central control building (CBLDG) at (in million \$):

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE  
07/02/84  
MOD2

1: .147832 2: .147832

Enter override value for CBLDG if desired, in million \$:

1: .147832 2: .147832

The central heat exchanger (and heat pump, if heat source is less than 120 degrees F) capital costs (CENF) are estimated to be (in million \$):

1: .245312 2: .245312

Enter override value for CENF if desired in million \$:

1: .245312 2: .245312

The total capital cost for the distribution system (DISTC) is estimated to be (in million \$):

1: .49833 2: .443518

Enter override value for DISTC if desired, in million \$:

1: .49833 2: .443518

The initial maintenance cost for the distribution system (CDO) is estimated to be (in million \$):

1: .014421 2: .013954

Enter override value for CDO if desired, in million \$:

1: .014421 2: .013954

Enter cost of electricity (CKW) in \$/kwh: .02

The distribution system's total initial operation and maintenance cost (DSTOM) is estimated to be (in million\$):

1: .030799 2: .026784

Enter override for DSTOM if desired, in million \$:

1: .030799 2: .026784

This completes the distribution module.

1)Print variables from MOD2 before returning to MENU

2)Return directly to MENU

Select a number: 2

BEGIN MOD3  
Enter community name: HEATVILLE  
Enter date in MM/DD/YY format: 07/02/84  
Enter service area name: CENTRAL  
Enter case name: SAMPLE - GEOTHERMAL

Typical values for the expected percentage of the total annual load (TTAS) to be met in each month are given below:

Enter override values, if desired:

	Assumed % of Annual Load	Override (as a decimal)
JAN	.14	
FEB	.12	
MAR	.1	
APR	.08	
MAY	.06	
JUN	.04	
JUL	.04	
AUG	.04	
SEP	.06	
OCT	.08	
NOV	.1	
DEC	.14	

Specify heat source

- 1)Waste Heat
- 2)Biomass
- 3)Geothermal

Select a number: 3

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE - GEOTHERMAL  
07/02/84  
MOD 3

- 1)Geothermal will be peaked with conventional fuel.
- 2)Geothermal will NOT be peaked with conventional fuel

Select a number: 1

The program assumes that 50% of the peak load will be met by the geothermal resource. Enter override value for GFRAC if desired, as a decimal:

Enter the following geothermal data and reliability levels (RL). Select and enter RL values for each geothermal data item from the following:

1.0 for test results from existing well(s) to be used in the project;  
0.9 for an estimate based on well(s) in the same production field;  
0.8 for an estimate based on well(s) in similar areas;  
0.6 for an estimate based only on surface geological information and literature review.

Enter maximum production well flow rate (FLOW) in gpm: 500  
Enter flow rate reliability level (RL1): 1  
Enter wellhead temperature (TEMP) in deg F: 90  
Enter temperature reliability level (RL2): 1  
Enter depth to production zone from surface (DEPTH) in feet: 600  
Enter production zone reliability level (RL3): 1  
Enter average drilling and casing cost (DRILL) in \$/foot: 125  
Enter drilling cost reliability level (RL4): 1  
Enter static water level below ground level (STATIC) in feet: 100  
Enter water reliability level (RL5): .9

The geothermal system's usable heat or temperature drop across the heat exchanger (GEODT) is estimated to be 35 deg F. Enter override value for GEODT if desired, in deg F:

The total number of geothermal production wells is estimated to be 2 wells. Enter override value for PWEL if desired:

The number of geothermal injection wells is estimated to 1 wells. Enter override value for IJWEL if desired:

Enter number of geothermal replacement wells (RPWEL) expected to be required over the life of the project: 0  
Enter potential number of geothermal dry holes (DRHOL) to be drilled over the life of the project: 0  
Enter expected drawdown in production wells (GDRDN) in feet: 75  
Enter geothermal exploration and land costs, in million \$  
1: .01                      2: .01

The total capital cost of geothermal wells over the life of the project is estimated to be (in million \$):

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE - GEOTHERMAL  
07/02/84  
MOD 3

1: .21625 2: .21625

Enter override value for GWCST if desired, in million \$:

1: .21625 2: .21625

Enter geothermal transmission pipeline right-of-way distance (GDIST) from the most favorable geothermal resource site to the central facility bldg location selected in Module 2, in miles: .2

Enter geothermal return transmission pipeline right-of-way distance (IJDST) from the cen.fac.bldg to an injection site, in miles. Enter '0' if injection is not being used: .1

Enter geothermal transmission pipeline installation cost correction factor (GPIPK) from following choices:

1.0 for highly urbanized service area with uncertain existing utility locations in rights-of-way;

0.75 for highly urbanized service area with known utility locations in rights-of-way;

0.50 for moderately urbanized service area;

0.35 for sparsely urbanized service area.

Enter selected GPIPK: .35

The geothermal supply and return transmission pipeline capital cost is estimated to be \$ .022955 million.

Enter override value for GPCST if desired, in million \$:

Pumping head is estimated to be 233.631 feet.

Enter override value for ADJHD if desired, in feet:

The program assumes a pump efficiency of 70% (GPEF).

Enter override value for GPEF if desired, as a decimal:

The geothermal pump capital cost is estimated to be

\$ .033729 Enter override value for PUCST if desired, in million \$:

The total capital cost for the geothermal system is

1: .27968 2: .27968

Enter override value for GCCST if desired, in million \$:

1: .27968 2: .27968

The initial geothermal system operation and maintenance cost is estimated to be \$

1: .010037 2: .010037

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE - GEOTHERMAL  
07/02/84  
MOD 3

Enter override value for GEOOM if desired in million \$:  
1: .010037 2: .010037

Type of peaking boiler:

- 1)Electric
- 2)Fossil

Select a number: 1

The capital cost of a conventional peaking boiler is  
estimated to be \$million.  
1: .05913 2: .05913

Enter override value for PBCST if desired, in million \$:  
1: .05913 2: .05913

The cost of electricity is estimated to be \$ 5.86  
per million Btu.

Enter override value for CPF if desired, in \$/million Btu:  
1: 5.86 2: 5.86

The items below are for both distrib. and heat source combined costs

The program assumes 20% of the capital cost as allowance for  
engineering and contingencies (ENG) for the project  
Enter override value for ENG if desired, as a decimal: .15

The total capital cost of the system is estimated to be (in million \$):  
1: .962711 2: .899677

Enter override value for SCST if desired, in million \$:  
1: .962711 2: .899677

The system's total initial operation and maintenance cost  
is estimated to be (in million \$):  
1 .048998 2 .044983

Enter override value for SMOM if desired, in million \$:  
1: .048998 2: .044983

This completes Module 3.  
1)Print Module 3 variables?  
2)Return directly to MENU  
Select a number: 2

BEGIN MOD 4  
Enter community name: HEATVILLE  
Enter date in MM/DD/YY format: 07/02/84  
Enter service area name: CENTRAL  
Enter case name: SAMPLE - GEOTHERMAL

Enter general economic inflation rate as a decimal:

First 5 years: .05  
Remaining years: .06

Enter electricity cost inflation rate as a decimal:

First 5 years: .06  
Remaining years: .07

Enter cost inflation for peaking as a decimal:.

First 5 years: .06  
Remaining years: .07

System ownership is

- 1) Public
- 2) Private

Select a number: 1

Enter percent of capital cost for insurance, as a decimal: .015

Enter inflation rate for insurance cost, as a decimal:

First 5 years: .02  
Remaining years: .03

The total capital cost for the system (SCST) in million \$ is:

1: .962711 2: .899677

Enter the amount to be debt financed (DEBT) in million \$:

1: .962711 2: .899677

Enter interest rate on DEBT as a decimal. Press [RETURN] with  
no input if there is no debt financing: .1

BEGIN SUBCASE # 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 4

FYS(2)= 18318.3 CUM. DIS. CASH FLOW=-.561959

You have defined an initial case which gives a negative  
cumulative discounted cash flow.

If you continue with this subcase you may revise your heat sales  
price (PSP) after this step, or you may need to revise your  
initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 4.5

FYS(2)= 18318.3 CUM. DIS. CASH FLOW=-.40698

You have defined an initial case which gives a negative  
cumulative discounted cash flow.

If you continue with this subcase you may revise your heat sales

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE - GEOTHERMAL  
07/02/84  
MOD 4

price (PSP) after this step, or you may need to revise your initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 5.5

FYS(2)= 18318.3 CUM. DIS. CASH FLOW=-.097021

You have defined an initial case which gives a negative cumulative discounted cash flow.

If you continue with this subcase you may revise your heat sales price (PSP) after this step, or you may need to revise your initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 5.65

FYS(2)= 18318.3 CUM. DIS. CASH FLOW=-.050527

You have defined an initial case which gives a negative cumulative discounted cash flow.

If you continue with this subcase you may revise your heat sales price (PSP) after this step, or you may need to revise your initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 5.8

FYS(2)= 18318.3 CUM. DIS. CASH FLOW=-.004034

You have defined an initial case which gives a negative cumulative discounted cash flow.

If you continue with this subcase you may revise your heat sales price (PSP) after this step, or you may need to revise your initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 5.85

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - GEOTHERMAL  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	PUMPING ELECTRICITY EXPENSE	PEAKING FUEL EXPENSE	BIOMASS FUEL EXPENSE	WASTE HEAT EXPENSE
----	-----	-----	-----	-----
1	\$0.	\$0.	\$0.	\$0.
2	\$2245.	\$5519.	\$0.	\$0.
3	\$2396.	\$5890.	\$0.	\$0.
4	\$2567.	\$6309.	\$0.	\$0.
5	\$2757.	\$6777.	\$0.	\$0.
6	\$2968.	\$7294.	\$0.	\$0.
7	\$3228.	\$7934.	\$0.	\$0.
8	\$3512.	\$8633.	\$0.	\$0.
9	\$3821.	\$9392.	\$0.	\$0.
10	\$4154.	\$10210.	\$0.	\$0.
11	\$4511.	\$11089.	\$0.	\$0.
12	\$4894.	\$12030.	\$0.	\$0.
13	\$5302.	\$13033.	\$0.	\$0.
14	\$5736.	\$14100.	\$0.	\$0.
15	\$6198.	\$15234.	\$0.	\$0.
16	\$6687.	\$16436.	\$0.	\$0.
17	\$7205.	\$17711.	\$0.	\$0.
18	\$7754.	\$19060.	\$0.	\$0.
19	\$8336.	\$20489.	\$0.	\$0.
20	\$8951.	\$22002.	\$0.	\$0.
21	\$9603.	\$23605.	\$0.	\$0.
22	\$10293.	\$25302.	\$0.	\$0.
23	\$11025.	\$27100.	\$0.	\$0.
24	\$11800.	\$29005.	\$0.	\$0.
25	\$12630.	\$31045.	\$0.	\$0.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - GEOTHERMAL  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	INSURANCE EXPENSE	ALL OTHER O&M EXPENSE	DEBT PRINCIPAL AND INTEREST EXPENSE	
----	-----	-----	-----	-----
1	\$0.	\$0.	\$106060.	
2	\$14729.	\$43757.	\$106060.	
3	\$15024.	\$45945.	\$106060.	
4	\$15325.	\$48243.	\$106060.	
5	\$15631.	\$50655.	\$106060.	
6	\$15944.	\$53187.	\$106060.	
7	\$16422.	\$56379.	\$106060.	
8	\$16915.	\$59761.	\$106060.	
9	\$17422.	\$63347.	\$106060.	
10	\$17945.	\$67148.	\$106060.	
11	\$18483.	\$71177.	\$106060.	
12	\$19038.	\$75447.	\$106060.	
13	\$19609.	\$79974.	\$106060.	
14	\$20197.	\$84773.	\$106060.	
15	\$20803.	\$89859.	\$106060.	
16	\$21427.	\$95251.	\$106060.	
17	\$22070.	\$100966.	\$106060.	
18	\$22732.	\$107024.	\$106060.	
19	\$23414.	\$113445.	\$106060.	
20	\$24116.	\$120252.	\$106060.	
21	\$24840.	\$127467.	\$106060.	
22	\$25585.	\$135115.	\$106060.	
23	\$26352.	\$143222.	\$106060.	
24	\$27143.	\$151815.	\$106060.	
25	\$27957.	\$160924.	\$106060.	

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - GEOTHERMAL  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	TOTAL ANNUAL EXPENSES	GROSS ANNUAL SALES	NET REVENUE AFTER EXPENSES
-----	-----	-----	-----
1	\$106060.	\$0.	-\$106060.
2	\$172311.	\$111809.	-\$60502.
3	\$175316.	\$118257.	-\$57058.
4	\$178503.	\$125653.	-\$52850.
5	\$181880.	\$134075.	-\$47805.
6	\$185453.	\$144962.	-\$40491.
7	\$190023.	\$157226.	-\$32797.
8	\$194882.	\$170955.	-\$23927.
9	\$200042.	\$186228.	-\$13814.
10	\$205517.	\$203109.	-\$2408.
11	\$211321.	\$221647.	\$10326.
12	\$217469.	\$241872.	\$24404.
13	\$223978.	\$263796.	\$39818.
14	\$230866.	\$287406.	\$56540.
15	\$238153.	\$312669.	\$74516.
16	\$245861.	\$339526.	\$93665.
17	\$254011.	\$367892.	\$113881.
18	\$262630.	\$397659.	\$135029.
19	\$271744.	\$428694.	\$156950.
20	\$281381.	\$460842.	\$179461.
21	\$291574.	\$493927.	\$202353.
22	\$302354.	\$527755.	\$225401.
23	\$313758.	\$562121.	\$248363.
24	\$325823.	\$596808.	\$270985.
25	\$338616.	\$633634.	\$295019.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - GEOTHERMAL  
 07/02/84  
 MOD 4

CASHFLOW STATEMENT

YEAR	EQUITY	NET CASH FLOW	DISCOUNTED CASH FLOW	CUMULATIVE DIS. CASH FLOW
----	-----	-----	-----	-----
1	\$0.	-\$106060.	-\$96418.	-\$96418.
2	\$0.	-\$60502.	-\$50001.	-\$146420.
3	\$0.	-\$57058.	-\$42869.	-\$189288.
4	\$0.	-\$52850.	-\$36097.	-\$225386.
5	\$0.	-\$47805.	-\$29683.	-\$255069.
6	\$0.	-\$40491.	-\$22856.	-\$277925.
7	\$0.	-\$32797.	-\$16830.	-\$294755.
8	\$0.	-\$23927.	-\$11162.	-\$305917.
9	\$0.	-\$13814.	-\$5858.	-\$311776.
10	\$0.	-\$2408.	-\$928.	-\$312704.
11	\$0.	\$10326.	\$3619.	-\$309085.
12	\$0.	\$24404.	\$7776.	-\$301309.
13	\$0.	\$39818.	\$11534.	-\$289775.
14	\$0.	\$56540.	\$14889.	-\$274886.
15	\$0.	\$74516.	\$17839.	-\$257048.
16	\$0.	\$93665.	\$20384.	-\$236663.
17	\$0.	\$113881.	\$22531.	-\$214133.
18	\$0.	\$135029.	\$24286.	-\$189847.
19	\$0.	\$156950.	\$25663.	-\$164184.
20	\$0.	\$179461.	\$26676.	-\$137508.
21	\$0.	\$202353.	\$27344.	-\$110164.
22	\$0.	\$225401.	\$27690.	-\$82475.
23	\$0.	\$248363.	\$27737.	-\$54738.
24	\$0.	\$270985.	\$27512.	-\$27226.
25	\$0.	\$295019.	\$27229.	\$3.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - GEOTHERMAL  
 07/02/84  
 MOD 4

Study Area No. ---	Favorability Rating -----	Favorability Ratio -----	Net Density of Annual Thermal Use (MBtu/Acre/Yr) -----	Gross Density of Annual Thermal Use (MBtu/Acre/Yr) -----
1	POSSIBLE	1.12212	234.775	247.132
2	FAVORABLE	1.77869	372.146	372.146
3	VERY FAVORABLE	6.75051	1412.37	1412.37

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE - GEOTHERMAL  
07/02/84  
MOD 4

BEGIN SUBCASE # 2

Enter proposed district heat sales price (PSP) in \$/million Btu: 5.25  
FYS(2)= 18318.3 CUM. DIS. CASH FLOW=-.047207  
You have defined an initial case which gives a negative  
cumulative discounted cash flow.  
If you continue with this subcase you may revise your heat sales  
price (PSP) after this step, or you may need to revise your  
initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 5.35  
FYS(2)= 18318.3 CUM. DIS. CASH FLOW=-.016212  
You have defined an initial case which gives a negative  
cumulative discounted cash flow.  
If you continue with this subcase you may revise your heat sales  
price (PSP) after this step, or you may need to revise your  
initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 5.45

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - GEOTHERMAL  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	PUMPING ELECTRICITY EXPENSE	PEAKING FUEL EXPENSE	BIOMASS FUEL EXPENSE	WASTE HEAT EXPENSE
----	-----	-----	-----	-----
1	\$0.	\$0.	\$0.	\$0.
2	\$2245.	\$5519.	\$0.	\$0.
3	\$2396.	\$5890.	\$0.	\$0.
4	\$2567.	\$6309.	\$0.	\$0.
5	\$2757.	\$6777.	\$0.	\$0.
6	\$2968.	\$7294.	\$0.	\$0.
7	\$3228.	\$7934.	\$0.	\$0.
8	\$3512.	\$8633.	\$0.	\$0.
9	\$3821.	\$9392.	\$0.	\$0.
10	\$4154.	\$10210.	\$0.	\$0.
11	\$4511.	\$11089.	\$0.	\$0.
12	\$4894.	\$12030.	\$0.	\$0.
13	\$5302.	\$13033.	\$0.	\$0.
14	\$5736.	\$14100.	\$0.	\$0.
15	\$6198.	\$15234.	\$0.	\$0.
16	\$6687.	\$16436.	\$0.	\$0.
17	\$7205.	\$17711.	\$0.	\$0.
18	\$7754.	\$19060.	\$0.	\$0.
19	\$8336.	\$20489.	\$0.	\$0.
20	\$8951.	\$22002.	\$0.	\$0.
21	\$9603.	\$23605.	\$0.	\$0.
22	\$10293.	\$25302.	\$0.	\$0.
23	\$11025.	\$27100.	\$0.	\$0.
24	\$11800.	\$29005.	\$0.	\$0.
25	\$12630.	\$31045.	\$0.	\$0.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - GEOTHERMAL  
 07/02/84  
 MOD 4

INCOME STATEMENT

YEAR	INSURANCE EXPENSE	ALL OTHER O&M EXPENSE	DEBT PRINCIPAL AND INTEREST EXPENSE	
----	-----	-----	-----	-----
1	\$0.	\$0.	\$99116.	
2	\$13765.	\$39542.	\$99116.	
3	\$14040.	\$41519.	\$99116.	
4	\$14321.	\$43595.	\$99116.	
5	\$14608.	\$45774.	\$99116.	
6	\$14900.	\$48063.	\$99116.	
7	\$15347.	\$50947.	\$99116.	
8	\$15807.	\$54004.	\$99116.	
9	\$16281.	\$57244.	\$99116.	
10	\$16770.	\$60679.	\$99116.	
11	\$17273.	\$64319.	\$99116.	
12	\$17791.	\$68179.	\$99116.	
13	\$18325.	\$72269.	\$99116.	
14	\$18875.	\$76605.	\$99116.	
15	\$19441.	\$81202.	\$99116.	
16	\$20024.	\$86074.	\$99116.	
17	\$20625.	\$91238.	\$99116.	
18	\$21243.	\$96712.	\$99116.	
19	\$21881.	\$102515.	\$99116.	
20	\$22537.	\$108666.	\$99116.	
21	\$23213.	\$115186.	\$99116.	
22	\$23910.	\$122097.	\$99116.	
23	\$24627.	\$129423.	\$99116.	
24	\$25366.	\$137188.	\$99116.	
25	\$26127.	\$145420.	\$99116.	

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - GEOTHERMAL  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	TOTAL ANNUAL EXPENSES	GROSS ANNUAL SALES	NET REVENUE AFTER EXPENSES	
----	-----	-----	-----	-----
1	\$99116.	\$0.	-\$99116.	
2	\$160186.	\$103909.	-\$56277.	
3	\$162961.	\$109902.	-\$53059.	
4	\$165908.	\$116775.	-\$49133.	
5	\$169032.	\$124602.	-\$44431.	
6	\$172341.	\$134719.	-\$37621.	
7	\$176572.	\$146117.	-\$30455.	
8	\$181072.	\$158876.	-\$22196.	
9	\$185854.	\$173070.	-\$12784.	
10	\$190928.	\$188758.	-\$2170.	
11	\$196309.	\$205986.	\$9678.	
12	\$202009.	\$224783.	\$22774.	
13	\$208045.	\$245157.	\$37112.	
14	\$214432.	\$267099.	\$52667.	
15	\$221190.	\$290577.	\$69388.	
16	\$228337.	\$315536.	\$87200.	
17	\$235894.	\$341898.	\$106004.	
18	\$243886.	\$369562.	\$125676.	
19	\$252337.	\$398404.	\$146068.	
20	\$261273.	\$428281.	\$167008.	
21	\$270723.	\$459028.	\$188305.	
22	\$280717.	\$490466.	\$209749.	
23	\$291290.	\$522404.	\$231114.	
24	\$302476.	\$554640.	\$252164.	
25	\$314337.	\$588864.	\$274527.	

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - GEOTHERMAL  
 07/02/84  
 MOD 4

# CASHFLOW STATEMENT

YEAR	EQUITY	NET CASH FLOW	DISCOUNTED CASH FLOW	CUMULATIVE DIS. CASH FLOW
----	-----	-----	-----	-----
1	\$0.	-\$99116.	-\$90105.	-\$90105.
2	\$0.	-\$56277.	-\$46510.	-\$136615.
3	\$0.	-\$53059.	-\$39864.	-\$176480.
4	\$0.	-\$49133.	-\$33558.	-\$210038.
5	\$0.	-\$44431.	-\$27588.	-\$237626.
6	\$0.	-\$37621.	-\$21236.	-\$258862.
7	\$0.	-\$30455.	-\$15628.	-\$274490.
8	\$0.	-\$22196.	-\$10355.	-\$284845.
9	\$0.	-\$12784.	-\$5422.	-\$290266.
10	\$0.	-\$2170.	-\$837.	-\$291103.
11	\$0.	\$9678.	\$3392.	-\$287711.
12	\$0.	\$22774.	\$7256.	-\$280455.
13	\$0.	\$37112.	\$10750.	-\$269705.
14	\$0.	\$52667.	\$13869.	-\$255836.
15	\$0.	\$69388.	\$16611.	-\$239225.
16	\$0.	\$87200.	\$18977.	-\$220248.
17	\$0.	\$106004.	\$20972.	-\$199275.
18	\$0.	\$125676.	\$22604.	-\$176672.
19	\$0.	\$146068.	\$23883.	-\$152788.
20	\$0.	\$167008.	\$24825.	-\$127964.
21	\$0.	\$188305.	\$25446.	-\$102518.
22	\$0.	\$209749.	\$25767.	-\$76751.
23	\$0.	\$231114.	\$25810.	-\$50941.
24	\$0.	\$252164.	\$25601.	-\$25340.
25	\$0.	\$274527.	\$25338.	-\$2.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - GEOTHERMAL  
 07/02/84  
 MOD 4

Study Area No.	Favorability Rating	Favorability Ratio	Net Density of Annual Thermal Use (MBtu/Acre/Yr)	Gross Density of Annual Thermal Use (MBtu/Acre/Yr)
---	-----	-----	-----	-----
1	POSSIBLE	1.12487	234.775	247.132
2	FAVORABLE	1.78306	372.146	372.146
3	VERY FAVORABLE	6.76707	1412.37	1412.37

BEGIN MOD3

Enter community name: HEATVILLE

Enter date in MM/DD/YY format: 07/02/84

Enter service area name: CENTRAL

Enter case name: SAMPLE - BIOMASS

Typical values for the expected percentage of the total annual load (TTAS) to be met in each month are given below:

Enter override values, if desired:

	Assumed % of Annual Load	Override (as a decimal)
JAN	.14	
FEB	.12	
MAR	.1	
APR	.08	
MAY	.06	
JUN	.04	
JUL	.04	
AUG	.04	
SEP	.06	
OCT	.08	
NOV	.1	
DEC	.14	

Specify heat source

1)Waste Heat

2)Biomass

3)Geothermal

Select a number: 2

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE - BIOMASS  
07/02/84  
MOD 3

Enter temperature of biomass heat source (BTEMP) in deg F: 140  
Enter peak heat available from biomass source (BPK) in Btu/hr: 24000000  
Enter annual heat available from biomass source (BAN) in Btu/yr: 270000000  
Enter percentage of peak biomass heat available by month,  
as a decimal. Each of the 12 values must be less than  
or equal to 1.0, and at least one value must equal 1.0:

JAN: .8  
FEB: .8  
MAR: .8  
APR: .8  
MAY: .8  
JUN: .8  
JUL: .8  
AUG: .8  
SEP: .8  
OCT: .9  
NOV: .9  
DEC: 1

Enter percentage of annual heat available by month, as  
a decimal. The 12 values entered must sum to 1.0

JAN: .14  
FEB: .12  
MAR: .1  
APR: .08  
MAY: .06  
JUN: .04  
JUL: .04  
AUG: .04  
SEP: .06  
OCT: .08  
NOV: .1  
DEC: .14

Enter the cost, if any, for the biomass at the source  
(BCST), in \$/million Btu: .25

The capital cost for a biomass boiler is estimated to be \$ .085218 million.

Enter override value for BBOIL if desired, in million \$:

Enter distance from biomass heat source to central heat  
exchanger facility (BDIST), in miles: .2

Enter biomass transmission pipeline installation cost  
correction factor from the following choices:

1.0 for highly urbanized service area with uncertain existing  
utility locations in rights-of-way;

0.75 for highly urbanized service area with known utility  
locations in rights-of-way;

0.50 for moderately urbanized service area;

0.35 for sparsely urbanized service area.

Enter selected BPIP: .35

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE - BIOMASS  
07/02/84  
MOD 3

The capital cost of the biomass transmission pipeline is estimated to be (in million \$):

1: .184704 2: .184704

Enter override value for BPCST if desired, in million \$:

1: .184704 2: .184704

The total capital cost for the biomass system is estimated to be (in million \$):

1: .295543 2: .295543

Enter override value for BCCST if desired, in million \$:

1: .295543 2: .295543

The initial operation and maintenance cost for the biomass system is estimated to be \$ .005542 million.

Enter override for BIOOM if desired, in million \$:

1)Bio or waste will be peaked with conventional fuel.

Type of peaking boiler:

- 1)Electric
- 2)Fossil

Select a number: 2

The capital cost of a conventional peaking boiler is estimated to be \$million.

1: .40212 2: .40212

Enter override value for PBCST if desired, in million \$:

1: .142 2: .142

Enter purchased cost of peaking fuel (CPF) in \$/million Btu:

1:5 2:5

The items below are for both distrib. and heat source combined costs

The program assumes 20% of the capital cost as allowance for engineering and contingencies (ENG) for the project

Enter override value for ENG if desired, as a decimal: .15

The total capital cost of the system is estimated to be (in million \$):

1: 1.07625 2: 1.01322

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE - BIOMASS  
07/02/84  
MOD 3

Enter override value for SCST if desired, in million \$:  
1: 1.07625            2: 1.01322

The system's total initial operation and maintenance cost  
is estimated to be (in million \$):  
1 .050275 2 .046260

Enter override value for SMOM if desired, in million \$:  
1: .050275            2: .04626

This completes Module 3.  
1)Print Module 3 variables?  
2)Return directly to MENU  
Select a number: 2

BEGIN MOD 4  
Enter community name: HEATVILLE  
Enter date in MM/DD/YY format: 07/02/84  
Enter service area name: CENTRAL  
Enter case name: SAMPLE - BIOMASS - PRIVATE OWNERSHIP

Enter general economic inflation rate as a decimal:  
First 5 years: .05  
Remaining years: .06

Enter electricity cost inflation rate as a decimal:  
First 5 years: .06  
Remaining years: .07

Enter BIOCOST inflation rate for first 5 years, as a decimal: .03  
Enter BIOCOST inflation rate for remaining years, as a decimal: .04

Enter cost inflation for peaking as a decimal:.  
First 5 years: .06  
Remaining years: .07

System ownership is  
1) Public  
2) Private  
Select a number: 2

Enter percent of capital cost for insurance, as a decimal: .015  
Enter inflation rate for insurance cost, as a decimal.  
First 5 years: .02  
Remaining years: .03

Enter percent of capital cost for property taxes as a decimal: .015

Enter inflation rate for property tax, as a decimal:  
First 5 years: .02  
Remaining years: .03

Enter combined rate of federal & state income taxes as a decimal: .3  
Enter required rate of return on equity, as a decimal: .15

Are alternate energy tax incentives applicable?  
1)Yes  
2)No  
Select a number: 2

The total capital cost for the system (SCST) in million \$ is:  
1: 1.07625 2: 1.01322

Enter the amount to be debt financed (DEBT) in million \$:  
1: .9 2: .9

Enter interest rate on DEBT as a decimal. Press [RETURN] with  
no input if there is no debt financing: .12

BEGIN SUBCASE # 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 5  
FYS(2)= 18318.3 CUM. A.T. DIS. CASH FLOW=-.600388

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
07/02/84  
MOD 4

You have defined an initial case which gives a negative cumulative after tax discounted cash flow.  
If you continue with this subcase you may revise your heat sales price (PSP) after this step, or you may need to revise your initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 5.5

FYS(2)= 18318.3 CUM. A.T. DIS. CASH FLOW=-.517857

You have defined an initial case which gives a negative cumulative after tax discounted cash flow.

If you continue with this subcase you may revise your heat sales price (PSP) after this step, or you may need to revise your initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 6

FYS(2)= 18318.3 CUM. A.T. DIS. CASH FLOW=-.436778

You have defined an initial case which gives a negative cumulative after tax discounted cash flow.

If you continue with this subcase you may revise your heat sales price (PSP) after this step, or you may need to revise your initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 7

FYS(2)= 18318.3 CUM. A.T. DIS. CASH FLOW=-.279303

You have defined an initial case which gives a negative cumulative after tax discounted cash flow.

If you continue with this subcase you may revise your heat sales price (PSP) after this step, or you may need to revise your initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 8

FYS(2)= 18318.3 CUM. A.T. DIS. CASH FLOW=-.127867

You have defined an initial case which gives a negative cumulative after tax discounted cash flow.

If you continue with this subcase you may revise your heat sales price (PSP) after this step, or you may need to revise your initial market penetration (IPS) by rerunning MOD1.

1)Continue with this subcase.

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
07/02/84  
MOD 4

2)Exit this subcase and go on to the next subcase.

Select a number: 1

Enter proposed district heat sales price (PSP) in \$/million Btu: 9

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	PUMPING ELECTRICITY EXPENSE	PEAKING FUEL EXPENSE	BIOMASS FUEL EXPENSE	WASTE HEAT EXPENSE
----	-----	-----	-----	-----
1	\$0.	\$0.	\$0.	\$0.
2	\$0.	\$7244.	\$4418.	\$0.
3	\$0.	\$7732.	\$4583.	\$0.
4	\$0.	\$8282.	\$4773.	\$0.
5	\$0.	\$8897.	\$4988.	\$0.
6	\$0.	\$9575.	\$5226.	\$0.
7	\$0.	\$10415.	\$5539.	\$0.
8	\$0.	\$11333.	\$5875.	\$0.
9	\$0.	\$12328.	\$6234.	\$0.
10	\$0.	\$13403.	\$6612.	\$0.
11	\$0.	\$14557.	\$7008.	\$0.
12	\$0.	\$15791.	\$7420.	\$0.
13	\$0.	\$17108.	\$7845.	\$0.
14	\$0.	\$18509.	\$8283.	\$0.
15	\$0.	\$19997.	\$8732.	\$0.
16	\$0.	\$21576.	\$9190.	\$0.
17	\$0.	\$23249.	\$9657.	\$0.
18	\$0.	\$25020.	\$10131.	\$0.
19	\$0.	\$26896.	\$10613.	\$0.
20	\$0.	\$28882.	\$11100.	\$0.
21	\$0.	\$30985.	\$11594.	\$0.
22	\$0.	\$33213.	\$12093.	\$0.
23	\$0.	\$35573.	\$12599.	\$0.
24	\$0.	\$38075.	\$13110.	\$0.
25	\$0.	\$40752.	\$13641.	\$0.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	PROPERTY TAX EXPENSE	INSURANCE EXPENSE	ALL OTHER O&M EXPENSE	DEBT INTEREST EXPENSE
----	-----	-----	-----	-----
1	\$0.	\$0.	\$0.	\$108000.
2	\$16467.	\$16467.	\$45613.	\$107190.
3	\$16796.	\$16796.	\$47894.	\$106283.
4	\$17132.	\$17132.	\$50288.	\$105267.
5	\$17475.	\$17475.	\$52803.	\$104129.
6	\$17824.	\$17824.	\$55443.	\$102854.
7	\$18359.	\$18359.	\$58769.	\$101427.
8	\$18909.	\$18909.	\$62296.	\$99828.
9	\$19477.	\$19477.	\$66033.	\$98037.
10	\$20061.	\$20061.	\$69995.	\$96032.
11	\$20663.	\$20663.	\$74195.	\$93786.
12	\$21283.	\$21283.	\$78647.	\$91270.
13	\$21921.	\$21921.	\$83365.	\$88452.
14	\$22579.	\$22579.	\$88367.	\$85296.
15	\$23256.	\$23256.	\$93669.	\$81762.
16	\$23954.	\$23954.	\$99290.	\$77803.
17	\$24673.	\$24673.	\$105247.	\$73370.
18	\$25413.	\$25413.	\$111562.	\$68404.
19	\$26175.	\$26175.	\$118255.	\$62843.
20	\$26960.	\$26960.	\$125351.	\$56614.
21	\$27769.	\$27769.	\$132872.	\$49638.
22	\$28602.	\$28602.	\$140844.	\$41824.
23	\$29460.	\$29460.	\$149295.	\$33073.
24	\$30344.	\$30344.	\$158252.	\$23272.
25	\$31254.	\$31254.	\$167748.	\$12294.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	INTANGIBLE DRILLING COSTS	TOTAL ANNUAL CASH EXPENSES	GROSS ANNUAL SALES	PRE-TAX CASH FLOW
----	-----	-----	-----	-----
1	\$0.	\$108000.	\$0.	-\$108000.
2	\$0.	\$197398.	\$170528.	-\$26870.
3	\$0.	\$200083.	\$180363.	-\$19720.
4	\$0.	\$202874.	\$191643.	-\$11231.
5	\$0.	\$205765.	\$204488.	-\$1277.
6	\$0.	\$208746.	\$221092.	\$12346.
7	\$0.	\$212867.	\$239797.	\$26929.
8	\$0.	\$217150.	\$260736.	\$43586.
9	\$0.	\$221586.	\$284030.	\$62444.
10	\$0.	\$226164.	\$309777.	\$83613.
11	\$0.	\$230871.	\$338051.	\$107180.
12	\$0.	\$235693.	\$368898.	\$133205.
13	\$0.	\$240614.	\$402335.	\$161721.
14	\$0.	\$245614.	\$438345.	\$192731.
15	\$0.	\$250674.	\$476876.	\$226202.
16	\$0.	\$255767.	\$517836.	\$262069.
17	\$0.	\$260868.	\$561099.	\$300232.
18	\$0.	\$265943.	\$606499.	\$340556.
19	\$0.	\$270957.	\$653834.	\$382876.
20	\$0.	\$275868.	\$702865.	\$426997.
21	\$0.	\$280627.	\$753325.	\$472698.
22	\$0.	\$285179.	\$804920.	\$519741.
23	\$0.	\$289460.	\$857333.	\$567873.
24	\$0.	\$293397.	\$910237.	\$616840.
25	\$0.	\$296944.	\$966403.	\$669459.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	DEPRECIATION	DEPLETION	TOTAL NON-CASH EXPENSES	NET INCOME BEFORE TAXES
----	-----	-----	-----	-----
1	\$0.	\$0.	\$0.	-\$108000.
2	\$153366.	\$0.	\$153366.	-\$180236.
3	\$224936.	\$0.	\$224936.	-\$244656.
4	\$214712.	\$0.	\$214712.	-\$225943.
5	\$214712.	\$0.	\$214712.	-\$215989.
6	\$214712.	\$0.	\$214712.	-\$202366.
7	\$0.	\$0.	\$0.	\$26929.
8	\$0.	\$0.	\$0.	\$43586.
9	\$0.	\$0.	\$0.	\$62444.
10	\$0.	\$0.	\$0.	\$83613.
11	\$0.	\$0.	\$0.	\$107180.
12	\$0.	\$0.	\$0.	\$133205.
13	\$0.	\$0.	\$0.	\$161721.
14	\$0.	\$0.	\$0.	\$192731.
15	\$0.	\$0.	\$0.	\$226202.
16	\$0.	\$0.	\$0.	\$262069.
17	\$0.	\$0.	\$0.	\$300232.
18	\$0.	\$0.	\$0.	\$340556.
19	\$0.	\$0.	\$0.	\$382876.
20	\$0.	\$0.	\$0.	\$426997.
21	\$0.	\$0.	\$0.	\$472698.
22	\$0.	\$0.	\$0.	\$519741.
23	\$0.	\$0.	\$0.	\$567873.
24	\$0.	\$0.	\$0.	\$616840.
25	\$0.	\$0.	\$0.	\$669459.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

# CASHFLOW STATEMENT

YEAR	PRE-TAX CASH FLOW	EQUITY	DEBT PRINCIPAL PAYMENT	
----	-----	-----	-----	-----
1	-\$108000.	\$176250.	\$6750.	
2	-\$26870.	\$0.	\$7560.	
3	-\$19720.	\$0.	\$8467.	
4	-\$11231.	\$0.	\$9483.	
5	-\$1277.	\$0.	\$10621.	
6	\$12346.	\$0.	\$11896.	
7	\$26929.	\$0.	\$13323.	
8	\$43586.	\$0.	\$14922.	
9	\$62444.	\$0.	\$16713.	
10	\$83613.	\$0.	\$18718.	
11	\$107180.	\$0.	\$20964.	
12	\$133205.	\$0.	\$23480.	
13	\$161721.	\$0.	\$26298.	
14	\$192731.	\$0.	\$29454.	
15	\$226202.	\$0.	\$32988.	
16	\$262069.	\$0.	\$36947.	
17	\$300232.	\$0.	\$41380.	
18	\$340556.	\$0.	\$46346.	
19	\$382876.	\$0.	\$51907.	
20	\$426997.	\$0.	\$58136.	
21	\$472698.	\$0.	\$65112.	
22	\$519741.	\$0.	\$72926.	
23	\$567873.	\$0.	\$81677.	
24	\$616840.	\$0.	\$91478.	
25	\$669459.	\$0.	\$102456.	

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

CASHFLOW STATEMENT

YEAR	INCOME TAX	INTANGIBLE DRILLING COSTS	INVESTMENT TAX CREDIT	ENERGY TAX CREDIT
----	-----	-----	-----	-----
1	\$0.	\$0.	\$0.	\$0.
2	\$0.	\$0.	\$107625.	\$0.
3	\$0.	\$0.	\$0.	\$0.
4	\$0.	\$0.	\$0.	\$0.
5	\$0.	\$0.	\$0.	\$0.
6	\$0.	\$0.	\$0.	\$0.
7	\$8079.	\$0.	\$0.	\$0.
8	\$13076.	\$0.	\$0.	\$0.
9	\$18733.	\$0.	\$0.	\$0.
10	\$25084.	\$0.	\$0.	\$0.
11	\$32154.	\$0.	\$0.	\$0.
12	\$39961.	\$0.	\$0.	\$0.
13	\$48516.	\$0.	\$0.	\$0.
14	\$57819.	\$0.	\$0.	\$0.
15	\$67861.	\$0.	\$0.	\$0.
16	\$78621.	\$0.	\$0.	\$0.
17	\$90070.	\$0.	\$0.	\$0.
18	\$102167.	\$0.	\$0.	\$0.
19	\$114863.	\$0.	\$0.	\$0.
20	\$128099.	\$0.	\$0.	\$0.
21	\$141809.	\$0.	\$0.	\$0.
22	\$155922.	\$0.	\$0.	\$0.
23	\$170362.	\$0.	\$0.	\$0.
24	\$185052.	\$0.	\$0.	\$0.
25	\$200838.	\$0.	\$0.	\$0.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

# CASHFLOW STATEMENT

YEAR	AFTER TAX CASHFLOW	AFTER TAX DISCOUNTED CASHFLOW	CUMULATIVE A.T.DISC CASHFLOW	
----	-----	-----	-----	-----
1	-\$291000.	-\$253044.	-\$253044.	
2	\$73195.	\$55346.	-\$197698.	
3	-\$28187.	-\$18533.	-\$216231.	
4	-\$20714.	-\$11843.	-\$228074.	
5	-\$11898.	-\$5916.	-\$233990.	
6	\$450.	\$195.	-\$233795.	
7	\$5527.	\$2078.	-\$231718.	
8	\$15588.	\$5096.	-\$226622.	
9	\$26998.	\$7675.	-\$218947.	
10	\$39811.	\$9841.	-\$209106.	
11	\$54061.	\$11620.	-\$197486.	
12	\$69763.	\$13039.	-\$184447.	
13	\$86907.	\$14125.	-\$170322.	
14	\$105458.	\$14904.	-\$155418.	
15	\$125354.	\$15405.	-\$140013.	
16	\$146502.	\$15656.	-\$124357.	
17	\$168782.	\$15684.	-\$108673.	
18	\$192044.	\$15518.	-\$93154.	
19	\$216106.	\$15185.	-\$77970.	
20	\$240762.	\$14711.	-\$63259.	
21	\$265776.	\$14121.	-\$49138.	
22	\$290892.	\$13439.	-\$35699.	
23	\$315834.	\$12688.	-\$23010.	
24	\$340310.	\$11889.	-\$11122.	
25	\$366166.	\$11123.	\$2.	

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

Study Area No.	Favorability Rating	Favorability Ratio	Net Density of Annual Thermal Use (MBtu/Acre/Yr)	Gross Density of Annual Thermal Use (MBtu/Acre/Yr)
---	-----	-----	-----	-----
1	POSSIBLE	1.1319	234.775	247.132
2	FAVORABLE	1.79419	372.146	372.146
3	VERY FAVORABLE	6.80931	1412.37	1412.37

COMMUNITY:HEATVILLE  
SERVICE AREA:CENTRAL  
CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
07/02/84  
MOD 4

BEGIN SUBCASE # 2

Enter proposed district heat sales price (PSP) in \$/million Btu: 8.5

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

INCOME STATEMENT

YEAR	PUMPING ELECTRICITY EXPENSE	PEAKING FUEL EXPENSE	BIOMASS FUEL EXPENSE	WASTE HEAT EXPENSE
----	-----	-----	-----	-----
1	\$0.	\$0.	\$0.	\$0.
2	\$0.	\$7244.	\$4418.	\$0.
3	\$0.	\$7732.	\$4583.	\$0.
4	\$0.	\$8282.	\$4773.	\$0.
5	\$0.	\$8897.	\$4988.	\$0.
6	\$0.	\$9575.	\$5226.	\$0.
7	\$0.	\$10415.	\$5539.	\$0.
8	\$0.	\$11333.	\$5875.	\$0.
9	\$0.	\$12328.	\$6234.	\$0.
10	\$0.	\$13403.	\$6612.	\$0.
11	\$0.	\$14557.	\$7008.	\$0.
12	\$0.	\$15791.	\$7420.	\$0.
13	\$0.	\$17108.	\$7845.	\$0.
14	\$0.	\$18509.	\$8283.	\$0.
15	\$0.	\$19997.	\$8732.	\$0.
16	\$0.	\$21576.	\$9190.	\$0.
17	\$0.	\$23249.	\$9657.	\$0.
18	\$0.	\$25020.	\$10131.	\$0.
19	\$0.	\$26896.	\$10613.	\$0.
20	\$0.	\$28882.	\$11100.	\$0.
21	\$0.	\$30985.	\$11594.	\$0.
22	\$0.	\$33213.	\$12093.	\$0.
23	\$0.	\$35573.	\$12599.	\$0.
24	\$0.	\$38075.	\$13110.	\$0.
25	\$0.	\$40752.	\$13641.	\$0.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	PROPERTY TAX EXPENSE	INSURANCE EXPENSE	ALL OTHER O&M EXPENSE	DEBT INTEREST EXPENSE
----	-----	-----	-----	-----
1	\$0.	\$0.	\$0.	\$108000.
2	\$15502.	\$15502.	\$41397.	\$107190.
3	\$15812.	\$15812.	\$43467.	\$106283.
4	\$16129.	\$16129.	\$45640.	\$105267.
5	\$16451.	\$16451.	\$47922.	\$104129.
6	\$16780.	\$16780.	\$50319.	\$102854.
7	\$17284.	\$17284.	\$53338.	\$101427.
8	\$17802.	\$17802.	\$56538.	\$99828.
9	\$18336.	\$18336.	\$59930.	\$98037.
10	\$18886.	\$18886.	\$63526.	\$96032.
11	\$19453.	\$19453.	\$67338.	\$93786.
12	\$20036.	\$20036.	\$71378.	\$91270.
13	\$20637.	\$20637.	\$75660.	\$88452.
14	\$21257.	\$21257.	\$80200.	\$85296.
15	\$21894.	\$21894.	\$85012.	\$81762.
16	\$22551.	\$22551.	\$90113.	\$77803.
17	\$23228.	\$23228.	\$95520.	\$73370.
18	\$23924.	\$23924.	\$101251.	\$68404.
19	\$24642.	\$24642.	\$107326.	\$62843.
20	\$25381.	\$25381.	\$113765.	\$56614.
21	\$26143.	\$26143.	\$120591.	\$49638.
22	\$26927.	\$26927.	\$127827.	\$41824.
23	\$27735.	\$27735.	\$135496.	\$33073.
24	\$28567.	\$28567.	\$143626.	\$23272.
25	\$29424.	\$29424.	\$152244.	\$12294.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	INTANGIBLE DRILLING COSTS	TOTAL ANNUAL CASH EXPENSES	GROSS ANNUAL SALES	PRE-TAX CASH FLOW
----	-----	-----	-----	-----
1	\$0.	\$108000.	\$0.	-\$108000.
2	\$0.	\$191254.	\$159014.	-\$32240.
3	\$0.	\$193689.	\$168185.	-\$25504.
4	\$0.	\$196220.	\$178703.	-\$17516.
5	\$0.	\$198838.	\$190681.	-\$8157.
6	\$0.	\$201534.	\$206164.	\$4630.
7	\$0.	\$205285.	\$223606.	\$18320.
8	\$0.	\$209178.	\$243131.	\$33954.
9	\$0.	\$213202.	\$264853.	\$51651.
10	\$0.	\$217345.	\$288861.	\$71516.
11	\$0.	\$221593.	\$315226.	\$93632.
12	\$0.	\$225931.	\$343990.	\$118059.
13	\$0.	\$230341.	\$375170.	\$144828.
14	\$0.	\$234802.	\$408748.	\$173946.
15	\$0.	\$239292.	\$444677.	\$205385.
16	\$0.	\$243785.	\$482872.	\$239088.
17	\$0.	\$248250.	\$523214.	\$274964.
18	\$0.	\$252656.	\$565549.	\$312893.
19	\$0.	\$256962.	\$609687.	\$352725.
20	\$0.	\$261125.	\$655408.	\$394283.
21	\$0.	\$265094.	\$702461.	\$437367.
22	\$0.	\$268811.	\$750572.	\$481760.
23	\$0.	\$272211.	\$799446.	\$527235.
24	\$0.	\$275217.	\$848778.	\$573562.
25	\$0.	\$277779.	\$901152.	\$623373.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

# INCOME STATEMENT

YEAR	DEPRECIATION	DEPLETION	TOTAL NON-CASH EXPENSES	NET INCOME BEFORE TAXES
----	-----	-----	-----	-----
1	\$0.	\$0.	\$0.	-\$108000.
2	\$144384.	\$0.	\$144384.	-\$176624.
3	\$211763.	\$0.	\$211763.	-\$237267.
4	\$202137.	\$0.	\$202137.	-\$219653.
5	\$202137.	\$0.	\$202137.	-\$210294.
6	\$202137.	\$0.	\$202137.	-\$197507.
7	\$0.	\$0.	\$0.	\$18320.
8	\$0.	\$0.	\$0.	\$33954.
9	\$0.	\$0.	\$0.	\$51651.
10	\$0.	\$0.	\$0.	\$71516.
11	\$0.	\$0.	\$0.	\$93632.
12	\$0.	\$0.	\$0.	\$118059.
13	\$0.	\$0.	\$0.	\$144828.
14	\$0.	\$0.	\$0.	\$173946.
15	\$0.	\$0.	\$0.	\$205385.
16	\$0.	\$0.	\$0.	\$239088.
17	\$0.	\$0.	\$0.	\$274964.
18	\$0.	\$0.	\$0.	\$312893.
19	\$0.	\$0.	\$0.	\$352725.
20	\$0.	\$0.	\$0.	\$394283.
21	\$0.	\$0.	\$0.	\$437367.
22	\$0.	\$0.	\$0.	\$481760.
23	\$0.	\$0.	\$0.	\$527235.
24	\$0.	\$0.	\$0.	\$573562.
25	\$0.	\$0.	\$0.	\$623373.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

CASHFLOW STATEMENT

YEAR	PRE-TAX CASH FLOW	EQUITY	DEBT PRINCIPAL PAYMENT	
----	-----	-----	-----	-----
1	-\$108000.	\$113220.	\$6750.	
2	-\$32240.	\$0.	\$7560.	
3	-\$25504.	\$0.	\$8467.	
4	-\$17516.	\$0.	\$9483.	
5	-\$8157.	\$0.	\$10621.	
6	\$4630.	\$0.	\$11896.	
7	\$18320.	\$0.	\$13323.	
8	\$33954.	\$0.	\$14922.	
9	\$51651.	\$0.	\$16713.	
10	\$71516.	\$0.	\$18718.	
11	\$93632.	\$0.	\$20964.	
12	\$118059.	\$0.	\$23480.	
13	\$144828.	\$0.	\$26298.	
14	\$173946.	\$0.	\$29454.	
15	\$205385.	\$0.	\$32988.	
16	\$239088.	\$0.	\$36947.	
17	\$274964.	\$0.	\$41380.	
18	\$312893.	\$0.	\$46346.	
19	\$352725.	\$0.	\$51907.	
20	\$394283.	\$0.	\$58136.	
21	\$437367.	\$0.	\$65112.	
22	\$481760.	\$0.	\$72926.	
23	\$527235.	\$0.	\$81677.	
24	\$573562.	\$0.	\$91478.	
25	\$623373.	\$0.	\$102456.	

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

# CASHFLOW STATEMENT

YEAR	INCOME TAX	INTANGIBLE DRILLING COSTS	INVESTMENT TAX CREDIT	ENERGY TAX CREDIT
----	-----	-----	-----	-----
1	\$0.	\$0.	\$0.	\$0.
2	\$0.	\$0.	\$101322.	\$0.
3	\$0.	\$0.	\$0.	\$0.
4	\$0.	\$0.	\$0.	\$0.
5	\$0.	\$0.	\$0.	\$0.
6	\$0.	\$0.	\$0.	\$0.
7	\$5496.	\$0.	\$0.	\$0.
8	\$10186.	\$0.	\$0.	\$0.
9	\$15495.	\$0.	\$0.	\$0.
10	\$21455.	\$0.	\$0.	\$0.
11	\$28090.	\$0.	\$0.	\$0.
12	\$35418.	\$0.	\$0.	\$0.
13	\$43449.	\$0.	\$0.	\$0.
14	\$52184.	\$0.	\$0.	\$0.
15	\$61616.	\$0.	\$0.	\$0.
16	\$71726.	\$0.	\$0.	\$0.
17	\$82489.	\$0.	\$0.	\$0.
18	\$93868.	\$0.	\$0.	\$0.
19	\$105818.	\$0.	\$0.	\$0.
20	\$118285.	\$0.	\$0.	\$0.
21	\$131210.	\$0.	\$0.	\$0.
22	\$144528.	\$0.	\$0.	\$0.
23	\$158171.	\$0.	\$0.	\$0.
24	\$172068.	\$0.	\$0.	\$0.
25	\$187012.	\$0.	\$0.	\$0.

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

CASHFLOW STATEMENT

YEAR	AFTER TAX CASHFLOW	AFTER TAX DISCOUNTED CASHFLOW	CUMULATIVE A.T.DISC CASHFLOW	
----	-----	-----	-----	-----
1	-\$227970.	-\$198235.	-\$198235.	
2	\$61522.	\$46520.	-\$151715.	
3	-\$33971.	-\$22337.	-\$174052.	
4	-\$26999.	-\$15437.	-\$189489.	
5	-\$18778.	-\$9336.	-\$198825.	
6	-\$7266.	-\$3141.	-\$201966.	
7	-\$499.	-\$188.	-\$202154.	
8	\$8846.	\$2892.	-\$199262.	
9	\$19443.	\$5527.	-\$193735.	
10	\$31343.	\$7748.	-\$185987.	
11	\$44578.	\$9582.	-\$176406.	
12	\$59161.	\$11058.	-\$165348.	
13	\$75082.	\$12203.	-\$153145.	
14	\$92309.	\$13046.	-\$140099.	
15	\$110782.	\$13614.	-\$126485.	
16	\$130415.	\$13937.	-\$112548.	
17	\$151095.	\$14041.	-\$98507.	
18	\$172680.	\$13953.	-\$84554.	
19	\$195000.	\$13702.	-\$70852.	
20	\$217862.	\$13311.	-\$57541.	
21	\$241045.	\$12807.	-\$44734.	
22	\$264306.	\$12211.	-\$32523.	
23	\$287388.	\$11546.	-\$20977.	
24	\$310015.	\$10830.	-\$10147.	
25	\$333905.	\$10143.	-\$3.	

COMMUNITY:HEATVILLE  
 SERVICE AREA:CENTRAL  
 CASE:SAMPLE - BIOMASS - PRIVATE OWNERSHIP  
 07/02/84  
 MOD 4

Study Area No.	Favorability Rating	Favorability Ratio	Net Density of Annual Thermal Use (MBtu/Acre/Yr)	Gross Density of Annual Thermal Use (MBtu/Acre/Yr)
---	-----	-----	-----	-----
1	POSSIBLE	1.14642	234.775	247.132
2	FAVORABLE	1.81721	372.146	372.146
3	VERY FAVORABLE	6.89668	1412.37	1412.37

Appendix B  
PROGRAM INPUT WORKSHEETS

This set of worksheets is intended to assist the user in preparing for and organizing the data necessary to execute program runs. These sheets can be photocopied and used for compiling the necessary input data, and planning the parameters of various cases which the user wishes to assess.

MODULE 1

Compounded inflation rate from 1985 to date: \_\_\_\_\_

Local annual heating degree days: \_\_\_\_\_

Winter outside design temperature: \_\_\_\_\_

MODULE 1 CONTINUED

Study Area No.: \_\_\_\_\_

Study Area acreage: \_\_\_\_\_

Actual heating load data for major facilities-

Annual space heating, in Btu/yr: \_\_\_\_\_

Annual water heating, in Btu/yr: \_\_\_\_\_

Peak industrial process heating load, in Btu/hr: \_\_\_\_\_

Annual industrial process heating load, in Btu/yr: \_\_\_\_\_

Enter total square footage for buildings in the study area exclusive of any facilities for which actual load values are entered above.

Enter Total Square Feet by  
Year of Construction

<1955      1955-75      >1975

Single-family	(BLDGTYPE 1)	_____	_____	_____
Multi-family	(BLDGTYPE 2)	_____	_____	_____
Mobile home	(BLDGTYPE 3)	_____	_____	_____
Hotel/motel	(BLDGTYPE 4)	_____	_____	_____
Office	(BLDGTYPE 5)	_____	_____	_____
Retail	(BLDGTYPE 6)	_____	_____	_____
Restaurant	(BLDGTYPE 7)	_____	_____	_____
Public assembly	(BLDGTYPE 8)	_____	_____	_____
Warehouse	(BLDGTYPE 9)	_____	_____	_____

Expected initial market penetration rate, as a decimal: \_\_\_\_\_

Expected ultimate market penetration rate, as a decimal: \_\_\_\_\_

MODULE 2

Service area name

Case name

Number of subcases

Study area numbers to  
be included in service  
area

Length of project life

Distribution pipeline  
installation cost  
correction factor

Assumed distribution  
fluid send-out temper-  
ature (95 to 210°F)

138

Cost of electricity in  
\$/kwh

MODULE 3

Service area name

Case name

Heat source

For geothermal cases:

Maximum production well  
flow rate, in gpm

MODULE 3 continued

Wellhead temperature,  
in degrees F

Depth to production  
zone, in feet

Average drilling and  
casing cost, in \$/ft

Static water level  
below ground level

Number of replacement  
wells required

Number of dry holes to  
be drilled

Expected drawdown in  
production wells, in ft.

Exploration and land  
costs, in million \$

Transmission pipeline  
distance from wellhead  
to central heat exchange  
facility, in miles

Return transmission  
pipeline distance to  
injection site, if appli-  
cable, in miles

MODULE 3 continued

For biomass or waste heat cases:

Temperature of biomass/  
waste heat source, in  
degrees F

Peak heat available from  
biomass/waste heat source  
in Btu/hr

Annual heat available  
from biomass/waste heat  
source, in Btu/yr

Percentage of peak  
biomass/waste heat avail-  
able by month, as a  
decimal

Percentage of annual heat  
available by month from  
biomass/waste heat, as a  
decimal

Cost, if any, for the  
biomass/waste heat at the  
source

Distance from biomass/  
waste heat source to  
central heat exchange  
facility, in miles

Biomass/waste heat trans-  
mission pipeline installa-  
tion cost correction  
factor

MODULE 3 continued

Type of conventional  
peaking boiler

Purchase cost of peaking  
fuel, in \$ million Btu

MODULE 4

General economic infla-  
tion rate, as a decimal  
First 5 years  
Remaining years

Electricity cost infla-  
tion rate, as a decimal  
First 5 years  
Remaining years

Cost inflation rate for  
peaking fuel, as a decimal  
First 5 years  
Remaining years

Cost inflation rate for  
biomass or waste heat, as  
a decimal  
First 5 years  
Remaining years

System ownership

Percent of capital cost  
for insurance, as a  
decimal

MODULE 4 continued

Inflation rate for insurance cost, as a decimal

First 5 years

Remaining years

If private, percent of capital cost for property taxes, as a decimal

If private, inflation rate for property tax, as a decimal

First 5 years

Remaining years

If private, combined rate of federal and state income taxes, as a decimal

If private, required rate of return on equity, as a decimal

Amount of capital cost to be debt financed, in million \$

Interest rate on debt financing, as a decimal

## Appendix C

### ENERGY UNIT, PRICE & EFFICIENCY CONVERSIONS WITH INFLATION ESTIMATES

The common unit of heat measurement in HEATPLAN is the British thermal unit (Btu) or million Btu (MBtu). One Btu is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit at the water's point of maximum density. To convert between other energy units, use the following factors:

To Convert	Into	Multiply By
Cubic feet, natural gas	therm	0.01
Gallons, No. 2 oil	Btu	138,700 <sup>1</sup>
Gallons, No. 4 oil	Btu	145,000 <sup>1</sup>
Gallons, No. 5 oil	Btu	148,000 <sup>1</sup>
Gallons, No. 6 oil	Btu	149,700 <sup>1</sup>
Kilowatt-hours	Btu	3,413
LPG (gallon)	Btu	95,500
Therms	Btu	100,000

1 These are average values. Since exact Btu content varies with type and source, contact supplier when extreme accuracy is essential.

Fuel-specific prices are difficult to compare because of their separate units of measurement. HEATPLAN uses a standardized price for all fuels expressed in dollars per million Btu (\$/MBtu).

In addition, combustion efficiencies vary widely from fuel to fuel, which results in different quantities of fuels having to be

purchased and combusted in order to obtain an equivalent amount of heat. Generally accepted efficiencies for fuels are 70% for natural gas and propane, and 60% for fuel oil.

The following table describes the formulas that can be used to convert fuel unit prices into a standardized dollar per million Btu price, including the effect of different efficiencies. Thus, when units are standardized and efficiencies included a true comparison is possible among fuels.

#### Electricity

$$\$0.00/\text{MBtu} = \$0.00/\text{kwh} \times 293$$

#### Natural gas

$$\$0.00/\text{MBtu} = (\$0.00/\text{therm} \times 10) / 0.7$$

#### Fuel oil

$$\$0.00/\text{MBtu} = (\$0.00/\text{gal} \times 7.1) / 0.6$$

#### Propane

$$\$0.00/\text{MBtu} = (\$0.00/\text{gal} \times 10.5) / 0.7$$

HEATPLAN also requires that the user enter estimated fuel price inflation rates that are used for estimating a district heating system's life-cycle costs. The table on the following page is provided to assist users in estimating energy inflation rates in Module 4.

FORECAST OF ENERGY PRICES IN WASHINGTON  
INFLATION AND FUEL PRICE INDICES RELATIVE TO 1984

March, 1984

	General Inflation Forecast	Real Fuel Price Escalation				
		Natural Gas	Heating Oil	Electric Utility		
				Type 1	Type 2	Type 3
1984	1.000	1.000	1.000	1.000	1.000	1.000
1985	1.042	.990	.990	1.120	1.020	1.060
1986	1.092	.990	.990	1.170	1.020	1.060
1987	1.150	1.000	1.000	1.200	1.040	1.120

Long-  
Range

1988-2000	6%/yr	1%/yr	1%/yr	1%/yr	.5%/yr	1%/yr
2001-2020	6%/yr	2%/yr	2%/yr	0%/yr	0%/yr	0%/yr

	Nominal Fuel Price Escalation				
	Natural Gas	Heating Oil	Electric Utility		
			Type 1	Type 2	Type 3
1984	1.000	1.000	1.000	1.000	1.000
1985	1.032	1.032	1.162	1.062	1.102
1986	1.082	1.082	1.276	1.113	1.155
1987	1.150	1.150	1.382	1.194	1.286

Long-  
Range

1988-2000	7%/yr	7%/yr	7%/yr	6.5%/yr	7%/yr
2001-2020	8%/yr	8%/yr	6%/yr	6%/yr	6%/yr

Note: A "Type 1" electric utility is a privately-owned utility in WA: Puget Power, WA Water Power, or Pacific Power & Light. A "Type 2" utility is a publicly owned utility that owns a good part of its own generation including Seattle City Light, Tacoma City Light, Grant Co PUD, Chelan Co PUD, Douglas Co PUD, Pond Oreille Co PUD, and Cowlitz Co PUD. A "Type 3" utility is one that is entirely, or largely, dependent on the Bonneville Power Administration, this is, any utility not listed above.

Sources: General inflation rate is for the implicit price deflator as forecast by the Washington Office of Finance & Management. All real fuel price escalation factors for fiscal years 1985 to 1987 are estimates by WSEO; the long-range forecasts are based on forecasts by BPA and the Northwest Power Planning Council.

## Appendix D

### ANNUAL HEATING DEGREE DAYS FOR SELECTED LOCATIONS IN WASHINGTON<sup>1</sup>

<u>County</u>	<u>Station</u>	<u>Annual Heating Degree Days</u>	<u>County</u>	<u>Station</u>	<u>Annual Heating Degree Days</u>
Adams	Othello	5858	Lewis	Centralia	4982
Asotin	Pomeroy	5767	Lincoln	Odessa	6148
Benton	Prosser	5570	Mason	Shelton	5241
Chelan	Stehekin	6795	Okanegan	Winthrop	7708
Callum	Port Angeles	5842	Pacific	Willapa	
Clark	Vancouver	4667		Harbor	5078
Columbia	Dayton	5628	Pond Oreille	Newport	7406
Cowlitz	Longview	5064	Pierce	Buckley	5501
Douglas	Waterville	7517	San Juan	Olga	5721
Ferry	Colville	7097	Skagit	Anacortes	5162
Franklin	Halton	6035	Skamania	Battle	
Garfield	Pomeroy	5767		Ground	6973
Grant	Ephrata	5603	Snohomish	Everett	5347
Grays Harbor	Aberdeen	5316	Spokane	Spokane	6835
Island	Coupeville	5609	Stevens	Colville	7097
Jefferson	Quilcene	5581	Thurston	Olympia	5530
King	Sea-Tac A.P.	5185	Wahkiakum	Longview	5064
Kitsap	Grapeview	4873	Walla Walla	Walla Walla	4835
Kittitas	Cle Elum	7020	Whatcom	Newhalem	5754
Klickitat	Goldendale	6294	Whitman	Colfax	6319
			Yakima	Yakima	6009

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<sup>1</sup> Temperature base is 65°F. Stations were chosen to be representative of their county; however, the counties of Asotin, Ferry, Franklin, Kitsap, Skamania, Wahkiakum, and Walla Walla are represented by stations outside their boundaries.

Source: U.S. Weather Service

## Appendix E

### OUTSIDE DESIGN TEMPERATURES FOR SELECTED LOCATIONS IN WASHINGTON

This Appendix presents winter outside design temperatures for 251 localities in Washington (Holladay, 1975). Temperatures for 11 localities with "a" after their names were developed from 5 to 22 years of hourly data, tabulated by computer. Localities marked "b" only record daily maximum and minimum temperatures, and the design levels were developed from 7 to 25 years of records, using ASHRAE methods. Temperatures for other localities without weather stations were interpolated using contour lines.

Winter temperatures in Washington are highly variable. Annual minimum temperatures may vary  $\pm 20$  °F from the values listed. The data listed does not represent the most severe conditions. The user must determine the predominant type of structure in a service area in terms of wood or masonry construction, and select a weighted average design temperature that reflects this mix of structure types.

<u>Station</u>	<u>Wood Structures</u>	<u>Masonry Structures</u>
Aberdeen (b)	24	28
Aberdeen 20 NNE (b)	21	25
Anacortes (b)	20	24
Anatone (b)	-12	-4
Appleton (b)	6	11
Auburn	17	25
Battleground (b)	15	19
Bellevue	20	24
Bellingham AP (b)	14	19
2N (b)	12	17

<u>Station</u>	<u>Wood Structures</u>	<u>Masonry Structures</u>
Benton City 2 NW (b)	6	11
Bickleton (b)	-1	4
Blaine (b)	13	17
Bothell 2 N (b)	12	17
Bremerton (b)	23	29
Brier	19	24
Buckley 1 NE (b)	16	26
Bumping Lake (b)	-10	-5
Burlington	15	19
Camas	17	21
Castle Rock	18	23
Cedar Lake (b)	15	20
Centralia (b)	16	21
Central Park	23	27
Chelan (b)	5	10
Cheney (b)	-3	4
Chesaw (b)	-16	-11
Chewelah 2 S (b)	-15	-9
Chief Joseph Dam (b)	1	6
Clellam Bay 1 NNE (b)	25	28
Clarkston (b)	2	10
Clearbrook (b)	14	19
Clearwater (b)	22	26
Cle Elum (b)	-5	1
Clyde Hill	20	24
Colfax 1 NW (b)	-3	2
College Place	-2	6
Colville AP (b)	-7	-2
Conconully (b)	-12	-7
Concrete (b)	15	19
Connell 4 NNW (b)	1	6
Cougar 5 E (b)	20	25
Coulee Dam 1 SW (b)	3	9
Coupeville 1 S (b)	18	21
Cushman Dam (b)	18	22
Dallesport AP (b)	9	14
Darrington RS (b)	8	13
Davenport (b)	-2	5
Dayton 1 WSW (b)	-2	5
Deer Park 2 E (b)	-12	-5
Des Moines	20	25
Diablo Dam (b)	10	15
Dishman	2	9
East Bremerton	23	29
Edmonds	19	24
Electron Headwks (b)	12	16
Ellensburg AP (b)	-4	2
CO (b)	-2	4
Elma (b)	20	24
Eltopia 6 W (b)	4	9
Elwha RS (b)	20	24
Enumclaw	16	26

<u>Station</u>	<u>Wood Structures</u>	<u>Masonry Structures</u>
Ephrata AP (b)	0	7
CO (b)	5	12
Everett JC (b)	18	23
Paine AFB (a)	16	21
Fircrest	23	29
Forks 1 E (b)	19	23
Fort Lewis (a)	18	24
Fruitvale	5	11
Glacier RS (b)	8	13
Glenoma (Kosmos) (b)	14	18
Goldendale (b)	2	7
Grandview	6	12
Grapeview (b)	24	30
Grayland 2 S (b)	24	28
Grays River Hatchery (b)	20	24
Greenwater (b)	9	14
Grotto (b)	16	21
Harrington 2 S (b)	-4	3
Hartline (b)	1	7
Hatton 8 E (b)	-4	1
Holden Village (b)	-1	4
Hoquiam AP (b)	22	26
Ice Harbor Dam (b)	12	17
Inchelium 2 NW (b)	-5	0
Issaquah	19	23
John Day Dam (b)	14	19
Kelso AP	19	24
Kennewick 10 SW (b)	8	13
Kent (b)	17	21
Kid Valley (b)	15	20
Kirkland	12	17
Lacey	12	17
Lacrosse 3 ESE (b)	-8	-3
La Grande (b)	19	23
Lake Cle Elum (b)	-4	1
Lake Forest Park	20	24
Lake Kachess (b)	2	3
Lake Keechelus (b)	0	5
Lakewood Center	23	29
Landsburg (b)	14	18
Larson AFB (a)	-1	6
Laurier (b)	-13	-8
Leavenworth (b)	-12	-7
Lind 3 NE (b)	-1	6
Linwood	3	10
Little Goose Dam (b)	16	22
Long Beach 3 NNE (b)	21	25
Longview (b)	19	24
Lower Granite Dam (b)	9	14
Lower Monument Dam (b)	13	18
Lynden	13	18
Lynnwood	19	24

<u>Station</u>	<u>Wood Structures</u>	<u>Masonry Structures</u>
Malott (b)	-1	4
Marietta 3 NNW (b)	13	18
Marysville	18	23
McMillin Res. (b)	17	21
McNary Dam (b)	5	11
Medical Lake	-3	4
Medina	20	24
Mercer Island	21	25
Metaline Falls (b)	-6	-1
Methow 2 W (b)	-4	1
Milton	23	29
Monroe (b)	16	21
Montesano 3 NW	22	26
Moses Lake 3 E (b)	-1	6
Mt. Adams RS (b)	0	6
Mountlake Terrace	17	22
Mt. Spokane Summit (b)	-9	-2
Mount Vernon 3 WNW (b)	16	20
Moxee City 10 E (b)	2	8
Mud Mountain Dam (b)	18	23
Nespelem 2 S (b)	-9	-4
Newhalem (b)	14	19
Newport (b)	-10	-5
Normandy Park	20	24
Northport (b)	-3	2
Oak Harbor	13	16
Oakville (b)	16	20
Odessa (b)	0	7
Olga 2 SE (b)	20	24
Olympia, Priest Pt. (b)	17	22
AP (b)	12	17
Omak 2 NW (b)	-2	3
Opportunity	1	8
Oroville (b)	0	5
Othello (b)	2	9
Packwood (b)	11	16
Palmer 3 SE (b)	18	22
Parkland	15	20
Pasco	8	13
Plain (b)	-9	-3
Pleasant View (b)	10	16
Pt. Grenville (b)	23	27
Pomeroy (b)	-5	3
Port Angeles (b)	24	28
Port Orchard	23	29
Port Townsend (b)	22	25
Priest Rapids Dam (b)	8	14
Prosser (b)	7	12
4NE (b)	6	11
Pullman Exp. Sta. (b)	-4	1
Puyallup (b)	15	19
Quilcene 2 SW (b)	18	23

<u>Station</u>	<u>Wood Structures</u>	<u>Masonry Structures</u>
Quillayute AP (b)	19	23
Quinault RS (b)	21	25
Quincy 1 NE (b)	-3	4
Ranier:		
Carbon River (b)	18	23
Longmire (b)	10	15
Paradise RS (b)	3	8
Raymond	24	28
Redmond	12	17
Renton	20	24
Republic (b)	-14	-9
Richland (b)	6	11
Rimrock Tieton Dam (b)	-2	4
Ritzville (b)	-1	6
Rosalia (b)	0	6
Ross Dam (b)	9	14
St. John (b)	9	15
Sappho 8 E (b)	19	23
Satus Pass (b)	4	10
Seattle Boeing (b)	21	25
Sea-Tac AP (a)	20	24
CO (b)	26	30
Jackson Park (b)	21	25
Maple Leaf (b)	19	23
U. of Washington (b)	22	26
Sedro Wooley 1 E (b)	14	19
Selah	5	11
Sequim (b)	20	23
Shelton (b)	18	23
Shoultes	18	23
Skamania Fish Hatchery (b)	19	24
Smyrna (b)	1	8
Snohomish	16	21
Snoqualmie Falls (b)	18	22
Pass (b)	1	6
South Broadway	5	1
So. Olympic Tree Farm (b)	20	24
Spanaway	16	20
Spokane AP (a)	-3	4
CO (a)	3	10
Fairchild AFB (a)	-3	4
Sprague (b)	-2	4
Stampede Pass (b)	2	7
Startup 1 E (b)	15	20
Stehekin 3 NW (b)	7	12
Steilacoom	15	21
Stevens Pass (b)	1	6
Stockdill Ranch (b)	-19	-14
Sumner	15	19
Sunnyside (b)	6	12
Tacoma McChord (a)	15	21
CO (b)	23	29

<u>Station</u>	<u>Wood Structures</u>	<u>Masonry Structures</u>
Tatoosh Island (b)	28	31
Thompson Place	15	20
Tieton Intake (b)	12	17
Toledo AP (b)	0	6
Toppenish	5	11
Trinidad 2 SSE (b)	7	13
Tukwila	20	24
Tumwater	12	17
University Place	23	29
Upper Baker Dam (b)	9	14
Vancouver (b)	18	22
Vashon Island (b)	23	28
Walla Walla AP (a)	-2	6
CO (b)	5	13
3 W (b)	-2	6
Wapato (b)	4	10
Washougal 8 ENE (b)	16	21
Waterville (b)	-4	1
Wawawai 2 NW (b)	9	14
Wellpinit (b)	-5	1
Wenatchee AP (b)	7	13
CO (b)	4	10
West Clarkston	2	10
Whidbey Island (a)	8	11
White River RS (b)	7	12
White Swan RS (b)	2	8
Whitman Mission (b)	4	11
Wilbur (b)	-2	4
Willapa Harbor (b)	22	26
Wilson Creek (b)	-4	3
Wind River (b)	10	15
Winthrop 1 WSW (b)	-17	-12
Yakima AP (a)	5	11

## Appendix F

### SELECTION OF STUDY AREAS

When the user is selecting the service area to be evaluated (either the entire community or the most favorable portion thereof), the first major step is to divide the service area into a series of small neighborhood study areas.

The size of study areas will depend on the level of detail desired by the user. Generally a study area should be one or more blocks grouped in logical configurations around the rights-of-way in which pipelines will most likely be calculated. HEATPLAN evaluates the favorability of each study area's heating load (expressed in terms of heat load per unit of land area, i.e. MBtu/hr/acre) in comparison with minimum heat sales per unit of land area required for the entire service area. Consequently the size and configuration of study areas will control the level of detail in the program's results.

In making choices about service and study areas, the user should keep the following general district heating prerequisites in mind:

- Areas should have high heat load densities. An area's heat load density is determined by the heat demand (space and water heating needs) per unit of land area; and the number and types of buildings

within the area. Heat load density is important because it is usually the major determinant of district heating capital and operating costs. Land uses such as residential, which do not have a high load per unit of floor space, can nonetheless have high heat load densities if multiple-family buildings have several floors and are relatively close together. Other areas such as industrial zones may have high heat load densities even though the buildings may be single-story and low in density, because the industrial heat load per unit of floor space can be very high. In many communities, the central business district is often the location with the highest heat load density.

Areas should have high load or utilization factors.

The load factor is the ratio between the actual amount of energy consumed annually to the amount of energy that would be consumed if the peak heating load were to be imposed continuously for a full year. A high load factor maximizes use of the geothermal resource and district heating system, i.e. it runs more often at full capacity thereby making better use of invested capital. Areas that have both high heat load density and a high load factor have a high density of annual

thermal use (identified as the GDAS value in HEATPLAN). These areas are the most attractive opportunities for district heating, since capital costs are relatively low per customer serviced, and can be recovered quickly from high heat sales per unit of land area, or per dollar of invested capital.

- Areas should be as close as possible to heat source sites. Close proximity to heat sources will reduce capital and operating costs, and also heat losses.
- Areas should include groups of buildings under single ownership wherever possible. A large group of heat loads under the control of one entity, e.g. a college, medical center, or planned unit development, represents a logical and attractive customer for a prospective district heating system.
- Areas should be selected so as to support other major community development objectives. For example, areas already targeted for new or redevelopment are often good candidates for district heating; or desired economic growth and diversification can be induced by offering competitively-priced district heat as a

locational incentive to new industrial or commercial activities.

- Areas should not include those land-uses which are obviously inapplicable to, or uneconomic for, district heating. Areas should be configured to avoid extremely low-density residential areas, e.g. less than four dwelling units per acre, and other dedicated open space, such as large parks, which are never likely to be the site of heat demands.

For additional discussion of preferred study area characteristics and selection criteria see: Allen, 1981; Georgia Institute, 1979; IDHA, 1983; Lienau, 1981; Lilljeqvist, 1978; LLC Geothermal, 1979; Pferdehirt, 1980; Pine, undated; and Wahlman, 1978.

## Appendix G

### COLLECTION OF ACTUAL HEATING LOAD DATA

The user can, and should, improve the accuracy of study area load estimates by using actual load data for major facilities in the study areas, e.g. schools, hospitals, or industries. Actual load data will fall into the following categories:

#### Space Heating

- Peak load for residential, commercial, institutional, and industrial uses, in Btu/hr.
- Annual load for residential, commercial, institutional, and industrial uses, in Btu/yr.

#### Water Heating

- Average hourly load for residential, commercial, institutional and industrial uses, in Btu/hr.
- Annual load for residential, commercial, institutional, and industrial uses, in Btu/yr.

#### Industrial Processing

- Peak process heating load, in Btu/hr.
- Annual process heating load, in Btu/yr.

Actual load data may be available through previous energy audits of facilities, or through a compilation of previous heating bills. The user is advised to seek assistance from a professional mechanical engineer in compiling and tabulating this data. The available data may already be expressed in Btu's, or they may be available but expressed in other units of energy, in which case they can be converted to Btu's using the conversion table at the front of the User Manual. The user should also collect estimates of heating system efficiencies for major facilities, and assure that actual load values are adjusted for the system's conversion efficiency, rather than the amount of energy purchased from a fuel distributor for the system. For example, oil-fired boilers usually have efficiencies ranging from 60-80%.

If peak and annual values have not been computed by the facility operator, the user should have a mechanical engineer compute the values, or the user may derive these values from: at least three years of utility or fuel bills for the facility; estimates of energy consumption by end-use, i.e. percent of the bills attributable to heating, cooling, lights, power equipment; and heating system efficiency. Given an annual average energy use (AAEU) for the facility, and a heating system efficiency estimates, the inputs required for HEATPLAN can be computed as follows:

ASAS = AAEU x percent of AAEU devoted to space heating  
(also note either wood or masonry construction)

AWAS = AAEU x percent of AAEU devoted to water heating

APHS = AAEU/[number of annual peak operation hours +  
(percent of annual hours at peak x annual hours off-  
peak)]

APAS = AAEU (if facility AAEU is strictly process heat)

## Appendix H

### COLLECTION OF BUILDING FLOOR SPACE DATA

Rather than trying to rely completely on actual load data, which can be time-consuming and sometimes difficult to collect, HEATPLAN's principal user input is an inventory of land-uses by building type and floor space. Quantities of floor space are multiplied by space and water heating demand coefficients, and aggregated into peak and annual heat loads for a given study area.

After the user has decided on the district heating service area, and the study areas within it, floor space data must be collected for each study area according to HEATPLAN's prescribed nine building types. Sources of floor space data are as follows:

- In Washington, county assessor appraisal methods include notation of the floor area of buildings on property records, except for certain tax-exempt facilities. Depending upon the county, this data may be retrieved by computer or manually. The advantages of county assessor floor space data include: its uniform availability for all types of land-uses; its continuous updating provides annually current data; data is already indexed to a base map showing parcelization in the study area; and in addition to floor space data, the

assessor records may also contain useful information on building age, and type of heating equipment (which is important to district heating market penetration) (also see Appendix I).

- General land-use and building inventories. Some communities may already maintain inventories of land-uses and buildings through their planning, building, or fire departments. Although such inventories do not always provide floor space data, such values may be derived by using typical floor space constants applied to the numbers of structures identified in such inventories. In residential areas constant floor space coefficients can be applied to dwelling unit counts. The most recent Washington figures for residences are (Hinman, 1980):

<u>Dwelling Type</u>	<u>Average Floor Space (sq.ft.)</u>
Detached single-family	1,500
Attached Single-family and 2-4 multiple-family	1,402
5 or more multiple-family	803
Mobile home	829
All households	1,338

- Windshield or walking inventory. Using aerial photographs to calculate lot coverage, floor area estimates can be compiled through a windshield or walking inventory of the area. Increased accuracy can be obtained by outside measurement of buildings using a wheel-mounted distance counter.
- U.S. Census Bureau data. The Census will provide block-level information on residential building size and energy use, but does not cover the commercial or institutional sectors. Also, Census data is only collected every 10 years, and is therefore soon out of date. There is also a service charge for retrieving and reproducing data from Census repositories.

The HEATPLAN categories of building types require classification of floor space by building age (to account for the general tendency of older buildings to consume more heat than new structures). The program assumes the following general timeframes:

<u>Date of Construction</u>	<u>Consumption Category</u>
Prior to 1955	HIGH
1955 - 1973	MEAN
1974 - present	LOW

It should also be noted that HEATPLAN can be used to model the floor space effects of new development proposals. For

example, the construction of a large quantity of floor space in a given study area could be evaluated in terms of its contribution towards improving the area's favorability for district heating. Results of development reviews in district heating target areas could be compared against minimum heat load densities established in a community heat plan. See Appendix L for a further discussion of land-use measures for improving geothermal district heating conditions.

## Appendix I

### DISTRICT HEATING MARKET PENETRATION RATES

The rate of market penetration for district heating is the rate at which customers hook-up or "retrofit" to the system; the local heating market is penetrated to the extent that competing fuels are displaced by district heating. To date, there has been very limited research or experience with penetration rates specific to district heating. Moreover, the incremental nature of penetration over time, from initial project start-up to the end of its useful life, has been considered in very few cases.

Generally, the market penetration rate for district heating will be a function of: the severity of the climate, i.e. number of annual heating degree days; the relative ease and cost of retrofitting existing building heating systems to district heat, e.g. existing electric resistance heat is very difficult and expensive to retrofit in comparison with oil-fired forced air; the age of existing building heating systems in terms of their remaining useful life and replacement plans; and the competitiveness of the district heat price in comparison to existing fuel prices, i.e. the district heat sales price must offer a savings sufficient to offset the customers' costs for retrofitting.

HEATPLAN relies on the user's subjective judgment about market penetration, requiring the user to assume initial (project start-up) and ultimate (end of system useful life) penetration rates for each study area. These judgments should be based on the factors described above, and if circumstances allow, the user may wish to conduct a market survey in the study areas to gauge customer interest in a geothermal district heating system.

The following examples of district heating penetration estimates have been drawn from communities where projects have been constructed or studied:

	Initial Penetration <u>Rate</u> <sup>1</sup>	Annual Growth <u>Rate</u> <sup>1</sup>	Ultimate Penetration <u>Rate</u> <sup>1</sup>
Boise, ID	32	-	-
Susanville, CA	10	-	-
Piqua, OH	34-472	-3	95
Klamath Falls, OR	-	-	100
Provo, UT	-	1.8	30
Detroit, MI	-	-	90
Moorhead, MN	-	-	90
Bellingham, WA	-	-	90
Vale, OR	-	-	77

---

1 Percent of local space and water heating market.

2 44% residential, 34% commercial, 47% industrial.

3 Annual rate varies over project life at 3 to 7%/yr depending on land-use type and year of project (faster annual growth rates occur in earlier years).

For users interested in a detailed discussion of district heating market penetration, one of the most extensive treatments of this issue appears in the Piqua, Ohio study (Georgia Institute of Technology et al., 1979).

## Appendix J

### HEAT SOURCE OPTIONS & TRANSMISSION PIPELINE ROUTING

HEATPLAN requires information on the proposed heat source in order to properly size and cost the district heating system. Data must be entered that describes the quantity and quality of either geothermal, biomass, or waste heat available to the project.

Ideally, geothermal data would come from actual exploration drilling and testing, or existing geothermal wells in the area. Alternatively, if a geothermal resource has not been completely confirmed, the best available estimates must be used and adjusted for reliability. The user may obtain advice on geothermal data and/or estimates from a professional geologist, hydrologist, or well driller. In addition, several agencies may be able to provide data on local conditions, or technical assistance in formulating resource estimates. These include:

- Geothermal Program Manager, Washington State Energy Office, 400 E. Union, Olympia, WA 98504 (resource data, technical assistance for resource and equipment estimates, and referrals).

- Geothermal Program Manager, Department of Natural Resources, Olympia, WA 98504 (geology and hydrology information).
- Local office of the Department of Ecology (records on groundwater and shallow well drilling).
- Oregon Institute of Technology Geo-Heat Center, Klamath Falls, OR 97601 (technical assistance for resource and equipment estimates, and project economic evaluations).
- U.S. Geological Survey, Menlo Park, CA. (various regional publications).

Ideally, biomass or waste heat data would come from previous evaluations of these sources, e.g. waste heat available from a particular industry or biomass heat available from a particular co-generation or incineration project. If detailed information on such resources are not readily available, the best available estimates must be used. The user should obtain professional advise on such estimates from knowledgeable engineering sources. In addition, agencies which may be able to provide assistance include:

- Biomass Program Manager, Washington State Energy Office, 400 E. Union, Olympia, WA 98504 (resource data, technical assistance for resource and equipment estimates, and referrals).
- Biomass Program Manager, Washington Department of Natural Resources, Olympia, WA 98504 (forestry-related information).

In addition to a primary heat source, the program also allows the user the option of including a conventional-fueled boiler for meeting a portion of the system's peak demands. Conventionally-fueled peaking may offer several advantages in terms of increased efficiencies and lower capital costs as follows:

- Where heat source development costs are unusually high, reliance on conventionally-fueled peaking will reduce alternate heat source demands, and in turn their development costs.
- Where the primary heat source temperatures are too low to effectively meet peak demands, conventionally-fueled peaking may be a cost-effective supplement to increase temperatures. This is similar to cases where very low-temperature heat resources are heat pumped to

district heating temperatures for both base and peak demands.

- Conventionally-fueled temperature increases for peak loads will allow a corresponding reduction in the size of pumps and pipelines, reducing capital and operating costs.

It should be noted, however, that a hybrid system using conventionally-fueled peaking will create capital and operating costs for the peaking boiler which would not otherwise be present. A community seriously considering a system should closely evaluate the engineering and economic trade-offs of primary source only versus hybrid heat supply, to determine which is superior for local conditions.

For further information on hybrid systems see IDHA, 1983; and Lienau, 1981.

HEATPLAN also requires that the user identify the distance of the most probable route for the system's transmission line, from the heat source site to the in the service area. In the case of a geothermal source it is important to note that this should be a distance sufficient to reach the furthest well likely to be drilled in a given production field, so as to account for collection pipe among multiple wells.

In selecting the transmission pipeline route, the user should select the shortest right-of-way route possible, while avoiding major physical obstacles, e.g. rivers or hills, which may increase costs. Large elevation increases between the heat source site and load area should be avoided to minimize pumping costs. Routes which provide a gravity head for fluids should be used wherever possible.

For additional information on pipeline routing see IDHA, 1983; Lienau, 1981; LLC Geothermal, 1979; Pferdehirt, 1980; and Wahlman, 1978.

## Appendix K

### HEAT PRICING

HEATPLAN requires that the user establish a first-year heat sales price for the district system. This price, expressed in dollars per million Btu, should be established at a level which is competitive with the prices of the most commonly used competing fuels in the area.

In formulating the district heat sales price, the user should collect the current unit costs for all fuels available in the community, and then convert these to prices in dollars per million Btu. If the user has a reasonable estimate of market share for each competing fuel, a weighted average cost for all competing fuels can be calculated. A weighted average price for competing fuels is usually a rough indication of the maximum district heat price that can be charged, and still be competitive enough to attract customers away from their existing fuel.

Alternatively, if competing fuel prices are much higher than expected district heating operational costs, district heat may be offered well below competing fuel prices so as to attract even more customers, thereby increasing market penetration rate, and in turn improving the district system's overall economic viability. For example, the most recent survey of geothermal direct heat prices in the U.S. indicates an average geothermal

sales price set at approximately 62% of competing natural gas prices; natural gas is specified because it was the most common, least cost alternative to geothermal in the 21 markets surveyed (Sifford, 1982).

Also, in cases where private operation of a system is being considered, it should be noted that Washington statutes and Utilities & Transportation Commission rules limit the price of alternate energy district heat to no more than 80% of the price of the most common and least expensive competing fuel in the community in cases where the operator's return on investment is not regulated. This restriction does not apply to publicly-operated systems.

## Appendix L

### LAND-USE PLANNING RECOMMENDATIONS FOR IMPROVING DISTRICT HEATING FAVORABILITIES

Communities can improve their long-range conditions for district heating by using their land-use planning powers to create more favorable locational arrangements, densities, and diversities of heating loads. The following is a brief list of land-use measures which may be considered for improving district heating feasibilities:

#### Comprehensive Plan

- Amend the Comprehensive Plan to incorporate a district heating section or element. Such an amendment will signify the importance of this energy resource and service to the community, and provide a policy framework to guide the nature and extent of future community actions.
- A district heating element in the Comprehensive Plan should include the following: 1) documentation of the alternate heat source potentials, e.g. recoverable heat, estimated to be available to the community over time, including probable heat source locations, and needs for site protection; 2) documentation of the community's various demands for heat, e.g. residential,

commercial, industrial; 3) evaluation of alternative courses of action to assure resource conservation, and economic and social gains through resource development; 4) establishment of policies to guide heat source conservation and district heating development according to preferred alternatives; and 5) identification of implementation measures, such as zoning and subdivision regulations, which can achieve policy objectives in the day-to-day community development process.

- Amend the land-use plan to identify the most favorable heat source areas, e.g. geothermal production fields, and designate them as significant resource sites requiring special development standards for future uses, so as to assure protection of the resource's long-term productivity by preventing conflicting uses.
- Amend the land-use plan to designate uses in proximity to heat sources according to the relative heating demands of the land-uses, such that the more heat-intensive uses are located closest to heat sources wherever practical.

### Zoning Ordinance

- Amend the zoning ordinance to address four issues critical to district heating favorabilities: density, diversity, rate of growth, and site standards (each are

discussed separately below). Also adopt zone changes consistent with land-use plan changes described above.

- Create a district heating (DH) overlay zone. This zone would encompass the boundaries of those neighborhoods considered for ultimate inclusion in a district heating system, regardless of their underlying zones, i.e. residential, commercial, or industrial. Special district heating measures would be applied through this overlay zone, as described below.
- Establish a minimum density standard and density bonus. Within the DH overlay zone all uses would be required to meet a minimum thermal load density, e.g. 0.15 MBtu/acre/hr. This would assure that new or redevelopment would result in heating loads that could be, at the least, economically served by district heating. Also, bonuses could be awarded to new or redevelopment which provides above average thermal load density, e.g. greater than 0.75 MBtu/acre/hr, or an above average load factor, e.g. greater than 25%. Bonuses could take the form of increases in maximum density limits, reduced off-street parking requirements, higher height limits, tax abatement, etc.
- Allow mixed uses in one area so as to increase heating load diversity, and thereby increase the area's load

factor. Within the DH overlay zone uses not otherwise permitted in the underlying zone should be allowed conditionally, if they can contribute significantly to an increased load factor for the immediate area, e.g. a 10% or greater increase, while still remaining compatible with immediately surrounding uses. Bonus incentives for mixed use developments could also be effectively offered through a planned unit development zone.

- Increase the rate of new growth or redevelopment in district heating target areas. Areas which will benefit the most from land-use incentives are the following: the principal heat source sites; major pipeline corridors; economic development areas or industrial parks; and areas which do not presently meet minimum thermal load densities for district heating. These types of target areas can be delineated within the DH overlay zone, and additional development bonuses offered to new or redevelopment which locates within such areas. Bonuses could take the form of additional reductions or variances in other non-energy standards while still maintaining compatibility with surrounding uses.
- Amend zoning performance standards to require reasonable exterior or service line access to building

heating equipment, so as to facilitate future retrofitting to district heating.

#### Subdivision Ordinance

- Amend the easement authority to specifically include easements for heat source operations and district heating pipelines and facilities.
- Amend lot and block design standards to encourage district heating-oriented design, e.g. clustering. Bonuses for such designs could be offered in the form of reductions or variances in non-energy related subdivision standards.
- Amend the list of required utilities to include discretionary power for requiring district heating pipeline and/or pipeline conduit where deemed necessary for future needs.

#### Capital Improvement Program

- Although not strictly a land-use planning measure, the preparation and use of a long-range capital improvement program for a district heating system will also bolster the community's ability to optimize the benefits of the system. A carefully engineered capital improvement program can serve as an important factual basis for the

land-use measures described above, while also assuring heat source protection and system optimization.

Appendix M  
PROGRAM DOCUMENTATION

MODULE 1

1. "Enter community name:"
2. "Enter date:"
3. "Enter compounded inflation rate from 1983 to date (COMPINT), as a decimal:"
4.  $HI = 1 + (COMPINT/100)$
5. "Enter local annual heating degree days (DD):"
6. "Enter winter outside design temperature, in OF (TW):"

Do not accept DD entry of less than 2000; if less than 2,000 is entered print "DEGREE DAY VALUE TOO LOW TO SUPPORT DISTRICT HEATING." Do not accept DD entry of more than 15,000; if more than 15,000 is entered print "DEGREE DAY VALUE IN ERROR, ENTER LOWER VALUE."

7. If  $DD > 7000$ , then  $CZN=1$  in Steps 18 and 19.  
If 5500-6999, then  $CZN=2$  in Steps 18 and 19.  
If 4000-5499, then  $CZN=3$  in Steps 18 and 19.  
If 2000-3999, then  $CZN=4$  in Steps 18 and 19.

7.1 Program stores annual space and water heating load by climate zone (CZN) and building type (BT) shown in Table M.1, in thousand Btu/sq.ft.-yr. The procedure used in preparing the loads table for HEATPLAN 2.0 consisted of taking the high value as the 80th percentile value, the low value as the 20th percentile value from the ES-4 table, and the mean value taken as a weighted average between those two bounding values. As an example, in Climate Zone 2, which would correspond to Region 2, the mean value for single family detached structures is 33,000 Btu's per square foot higher than the low value and 31,000 Btu's below the high value. In HEATPLAN 1.0, a peak value was computed and from this peak, the annual averages derived using a modified version of the formula shown on Page 28.2 of the 1982 ASHRAE Handbook of Fundamentals. This procedure can be found in the listings of HEATPLAN Version 1.0 at line 400 plus 12. HEATPLAN 2.0, on the other hand, begins with the annual data arrived at by multiplying the areas input times the statistically derived BEPS data, for the given building type, climate zone, and age of construction. It was presumed that buildings constructed prior to 1955 would generally have, and fall into the high category within any given climate zone. Those constructed after 1975, and the impact of the first era oil embargo, would generally qualify in the low category. Buildings built between 1955 and 1975 were categorized in the main area. In HEATPLAN 2.0, once the annual energy use for a study area is determined, the

Table M.1

Annual Space &amp; Water Heating Load (thousand Btu/yr/sq.ft.)

BLDGTYPE	CLIMATEZONE1				CLIMATEZONE2				CLIMATEZONE3				CLIMATEZONE4			
	HIGH		LOW		HIGH		LOW		HIGH		LOW		HIGH		LOW	
	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
BT1. Single-family	123.0	104.0	68.0	61.0	104.0	73.0	40.0	61.0	97.0	61.0	33.0	61.0	77.0	52.0	31.0	61.0
BT2. Multi-family	26.9	20.3	11.9	1.8	27.6	19.6	10.8	1.7	22.4	14.4	9.1	1.2	12.9	10.8	6.3	0.9
BT3. Mobile home	132.0	103.0	66.0	70.0	102.0	84.0	55.0	70.0	98.0	81.0	54.0	70.0	83.3	67.0	49.0	70.0
BT4. Hotel/motel	22.8	22.8	22.8	5.9	23.5	19.3	11.9	5.0	24.6	21.6	16.6	5.6	31.8	28.8	15.6	7.5
BT5. Office	21.4	18.5	15.7	2.0	26.5	21.6	17.9	2.3	23.3	18.5	13.9	2.0	19.4	17.4	12.8	1.8
BT6. Retail	35.4	29.2	21.2	5.5	39.5	28.9	19.8	5.4	28.6	25.4	20.3	4.7	26.8	23.9	21.2	4.5
BT7. Restaurant	63.5	55.9	39.3	31.6	76.2	61.4	38.3	34.7	80.0	64.2	36.6	36.3	52.8	49.7	35.2	28.1
BT8. Public assembly	26.7	26.7	26.7	3.5	47.3	35.0	21.2	4.6	34.5	30.3	24.4	3.9	26.7	23.5	19.3	23.5
BT9. Warehouse	56.3	56.3	56.3	0.4	74.2	61.5	45.8	0.4	60.0	48.7	36.0	0.3	37.5	37.5	37.5	0.3

## Notes:

1. Data derived from "Phase One/Base Data for the Development of Energy Performance Standards for New Bldgs." AIA Research Corp., Jan. 1978, figures ES-4.
2. Ratios for High, Mean, and Low uses derived from "Phase 2 Development of Energy Performance Standards," Syska & Hennessey Information Systems, Jan., 1979.

Table M.2

RATIOS USED TO DETERMINE HEATING AND DOMESTIC HOT WATER  
FOR BUILDING TYPES(Ref. S&H IS 1, 1979)<sup>1</sup>

<u>Building Type</u>	<u>Heating</u>	<u>Domestic Hot Water</u>
Public Assembly	40204/86573 = .46	5001/86573 = .06
Retail	28372/87088 = .33	3594/87088 = .04
Offices <sup>2</sup>	24003/76995 = .31	2861/76995 = .04
Restaurants	47554/141637 = .34	29520/141637 = .21
Warehouse <sup>3</sup>	46996/62260 = .75	323/62260 = .01
Apartment	31920/62938 = .51	1048/62938 = .02

- 
- 1 Using the Mean of Unweighted original design without resource utilization factors.
  - 2 "Small" Offices data (mean area = 16650 sf) used
  - 3 Labeled "Storage" in SHIS document

annual value is used in the equation described as Step 22, in the HEATPLAN 2.0 documentation. The equation shown in Step 22 is simply that shown on Page 28.2 of the Fundamentals book, solved for peak heat design loss, rather than for annual energy use. Comparisons between Versions 1.0 and 2.0 of HEATPLAN will generally show a difference of between two and four, over those completed in HEATPLAN 1.0. This is due to the fact that HEATPLAN 1.0 did not utilize the factor "K", shown in the equation in the Fundamentals book, and known as conservation factor in the HEATPLAN documentation. The conservation factors of HEATPLAN Version 2.0 have been assigned values 1, 2, and 3.. Three has been assigned to buildings that are past 1975. Two, for buildings constructed in the 1955 to 1975 period. One, for buildings built prior to 1955.

8. "Enter study area number:" 1 to 99 is valid entry.
9. "Enter study area gross land area (GAS) in acres:"
10. "Enter any actual heating load data available for study area as follows (enter NA if data is unavailable or not applicable):"

"Actual annual space heating (ASAS) in Btu/yr:"

"Actual annual water heating (AWAS) in Btu/yr:"

"Actual peak industrial process load (APHS) in Btu/hr:"

"Actual annual industrial process load (APAS) in Btu/yr:"

11. "The program assumes an actual space heating load factor (ACTLD) of 0.25. Enter override value for ACTLD if desired, as a decimal:"

12.  $ASHS = ASAS / [ACTLD \times 8,760]$

Where: ASHS = actual peak space load in study area, in  
Btu/hr

ASAS = actual annual space heating load in study  
area, in Btu/hr

ACTLD = load factor

8,760 = annual hours

13.  $AWHS = AWAS / 8,760$

Where: AWHS = actual average hourly water heating load in  
study area, in Btu/hr

AWAS = actual annual water heating load in study  
area, in Btu/yr

8,760 = annual hours

14.  $ATHS = ASHS + APHS$

Where: ATHS = actual total peak load in study area, in  
Btu/yr

ASHS = actual peak space heating load in study area,  
in Btu/yr

APHS = actual peak industrial process load in  
study area, in Btu/yr

15.  $ATAS = ASAS + AWAS + APAS$

Where:  $ATAS$  = actual total annual heating load in study  
area, in Btu/yr

$APAS$  = actual annual industrial process load in  
study area, in Btu/yr

16. Not used.

17. "Enter total square footage for buildings in the study area  
exclusive of any buildings for which actual load values were  
entered above. Enter footage according to date of  
construction categories of HIGH consumption (before 1955),  
MEAN consumption (1955-1975), or LOW consumption (after  
1975):"

		Enter Total Square Feet by Year of Construction		
		<u>&gt;1955</u>	<u>1955-75</u>	<u>&lt;1975</u>
Single-family	(BT1)			
Multi-family	(BT2)			
Mobile home	(BT3)			
Hotel/motel	(BT4)			

		<u>&gt;1955</u>	<u>1955-75</u>	<u>&lt;1975</u>
Office	(BT5)			
Retail	(BT6)			
Restaurant	(BT7)			
Public assembly	(BT8)			
Warehouse	(BT9)			

18. The program selects appropriate CZN from Step 7 and applies Step 17 input to Step 7.1 table by calculating study area annual space load for buildings as shown in the following example:

$$A(BT, HIGH) = \text{sq.ft. (HIGH)} \times HTLD (BT, CZN, HIGH)$$

Where:

$A(1, HIGH)$  = Annual space heating FOR BT1 and  
HIGH category

$\text{sq.ft.}(HIGH)$  = Sq.footage in HIGH category for BT1.

$HTLD (BT, CZN, HIGH)$  = Building energy performance factor in  
HIGH category for BT1 and CZN

Repeat for all building types and HIGH, MEAN, and LOW categories. This is the end of the loop begun in Step 17.

19. Store following table:

If CZN=1 then D = 8,000

If CZN=2 then D = 6,250

If CZN=3 then D = 4,750

If CZN=4 then D = 3,000

20. DELTATEE = 68 - TW

21. Not used.

22. Program calculates peak space heating by building type and consumption category as shown in this example for BT 1 to 9 and CONSV category 1 to 3:

$$PK_{BT} = (ABT, \text{ CONSV CAT} \times DELTATEE \times \text{CONSVCATEGORY}) / (D(CZN) \times 24 \times (1.139735 - 0.054865 \times \ln(D(CZN)))) + PK_{BT}$$

where: DELTATEE = difference between 68°F and the outside design temperature (TW)

$PK_{BT}$  = peak space heating for BT1, in Btu/hr

ABT = annual space heating for BT1, in Btu/yr

D = Mean Heating Degree Days

24 = Hours/day

$1.139735 - 0.054865 \times \ln(D(CZN))$  = correction factor defined on Fig. 1 page 28.3 of ASHRAE Fundamentals. Ln is natural logarithm.

CONSV = is a conservation factor which relates energy conservation or lack thereof, oversizing, and "pick-up" load contributions. Depending on date of construction CONSV will equal:

CONSV<sub>1</sub> = 2.0 for new buildings with current insulation practices and conservation features (post 1975)

CONSV<sub>2</sub> = 3.0 for buildings with some insulation (1955 to 1975)

CONSV<sub>3</sub> = 4.0 for buildings with little or no insulation (pre-1955)

Repeat equation for all BT's with Square Footages in each consumption category. End of loop started in Step 22.

23. Sum the peak space heating of all BT. Sum equals TOTPH.

TOTPH = 0

For M = 1 to 9

TOTPH = TOTPH + PK<sub>M</sub>

Next M

24. Program uses same CZN and calculates annual water heating by BT from Steps 16 and 17: (for BT 1 to 9)

$$\begin{aligned}
 WH_M &= \text{Sq. footage} \times WH \\
 &= (B_{BT, \text{ CONSV1}} + B_{BT, \text{ CONSV2}} + B_{BT, \text{ CONSV3}}) \times \\
 &\quad CCZN, BT, CAT4
 \end{aligned}$$

where:  $WH_M$  = Annual wasan pihzyue 'lyw BTM in Btu/yr

Repeat for each BT.

25. Sum annual water heating for all BT. Sum equals TOTAW.

26. Calculate total study area peak water heating:

$$TOTPEAKWTR = TOTAW / 8,760$$

Where: TOTPEAKWTR = Total study area peak water, in Btu/hr.

27. The program calculates non-diversified peak load in the study area (TTHS) (excluding average hourly tfan seating) in Btu/hr, by summing the study area non-diversified peak space heating load (TOTPH) together with any actual peak load (ATHS) identified in Step 10.

$$27.1 \text{ TWHS} = TOTPEAKWTR + AWHS$$

28. "The program uses a typical peak load diversity factor (DV) of 0.7. Enter an override value for DV if desired, as a decimal:"

29.  $TDHS = (TTHS \times DV) + TWHS$

Where:  $TDHS$  = total diversified peak heating load in study area, in Btu/hr

$TTHS$  = total non-diversified peak heating load in study area (excluding average hourly water heating) in Btu/hr

$DV$  = diversity factor

$TWHS$  = total average hourly water heating load in study area, in Btu/hr

30. "The program assumes a typical distribution heat loss in district heating (HLOSS) of 5% (0.05). Enter override value for HLOSS if desired, as a decimal."

31.  $TLHS = TDHS \times (1 + HLOSS)$

Where:  $TLHS$  = total study area peak, including diversification factor and distribution losses, in Btu/hr

32. The program sums study area annual space heating loads (A1 through A9 from Step 18), plus the annual water heating load for all buildings (TOTAW), plus any actual total annual load (ATAS from Step 10), to equal total annual load in study area (TTAS) in Btu/yr.

33.  $PTDS = TLHS / GAS$

Where:  $PTDS$  = diversified peak heat load density for  
study area, in Btu/acre/hr

$GAS$  = study area gross land area in acres

34.  $LFS = TTAS / (TLHS \times 8,760)$

Where:  $LFS$  = study area load factor

$TTAS$  = total annual load in study area, in Btu/yr

8,760 = annual hours

35.  $GDAS = (TTAS / GAS) \times 10^{-6}$

Where:  $GDAS$  = gross density of annual thermal use in study  
area, in MBtu/acre/yr

36. "Enter initial market penetration rate (IPS) and ultimate  
market penetration rate (UPS) penetration expected for  
district heating in the study area, as decimals:"

"IPS = \_\_\_\_\_"

"UPS = \_\_\_\_\_"

37.  $NDAS < GDAS \times UPS$

Where:  $NDAS$  = net density of annual thermal use in study area, in MBtu/acre/yr

38.  $TUHS = TLHS \times UPS$

Where:  $TUHS$  = total ultimately penetrated peak load for study area, in Btu/hr

39.  $TUAS = TTAS \times UPS$

Where:  $TUAS$  = total ultimately penetrated annual load for study area, in Btu/yr

40.  $TIAS = TTAS \times IPS$

Where:  $TIAS$  = total initially penetrated annual load for study area, in Btu/yr

41. The following arrays are passed in files to later Modules:  $SAN$ ,  $COMM\$,$   $DATE\$,$   $GAS,$   $ASAS,$   $AWAS,$   $APHS,$   $APAS,$   $ASHS,$   $AWHS,$   $TOTPEAKWTR_N,$   $TTHS,$   $,TDHS,$   $TLHS,$   $TTAS,$   $PTDS,$   $LFS,$   $GDAS,$   $IPS,$   $UPS,$   $NDAS,$   $TUHS,$   $TUAS,$   $TIAS.$  Each of these must be passed for each study area (SAI).

## MODULE 2

42. "Enter community name:"
43. "Enter service area name:"
44. "Enter case name:"
45. "Enter date:" Print Community Name, Service Area Name, Case Name, and Date in upper corner of every output page.
46. "Enter number of subcases to be evaluated when offered as an option for user inputs:" Program allows up to 5 subcases for sensitivity evaluation to be run from special inputs as noted below. This loop goes to the end of the program.
47. "Enter study area numbers for those to be included in service area. Enter COMPLETE when all study area numbers are entered."
48. Program sums the total ultimately penetrated peak load (TUHS) for all selected study areas to equal the gross diversified peak service area load adjusted for ultimate market penetration (JP) in Btu/hr.
49. "The total diversified peak load for the service area adjusted for ultimate market penetration (JP) is estimated

to be [display JP value solved above] Btu/hr. Enter override value for JP if desired, in Btu/hr:"

50. The program sums the total ultimately penetrated annual load (TUAS) for all selected study areas to equal the total annual service area load adjusted for ultimate market penetration (JA) in Btu/yr.
51. "The total annual load for the service area adjusted for ultimate market penetration (JA) is estimated to be [display JA value solved above] Btu/yr. Enter override value for JA if desired, in Btu/yr:"
52. The program sums the total annual load for all selected study areas (TTAS) to equal the annual service area load unadjusted for market penetration (JAX), in Btu/yr.
53. The program sums the total initially penetrated annual load (TIAS) for all selected study areas to equal the gross annual service area load adjusted for initial market penetration (JAY), in Btu/yr.
54.  $IP = JAY/JAX$

Where:  $IP$  = weighted average initial market penetration rate for service area, as a decimal

JAY = gross annual service area load adjusted for  
initial market penetration, in Btu/yr

JAX = gross annual service area load unadjusted  
for market penetration, in Btu/yr

55.  $UP = JA/JAX$

Where: UP = weighted average ultimate market penetra-  
tion rate for service area, as a decimal

JA = total annual service area load adjusted for  
ultimate market penetration, in Btu/yr

56.  $MS(2) = IP/UP$

Where: MS(2) = district heating initial market share, as a  
decimal.

56.1 Allow override for MSB.

57. "Enter length of project life (LIFE) from 10 to 25 years:"

58. "Enter market share expected for district heating in the  
service area, as a decimal, for each year of the project's  
operating life:"

DISPLAY FOLLOWING TABLE; ALLOW NUMBER OF SUBCASES FROM STEP  
46 TO BE ENTERED:

Delta = 1 - MSB

INC. = 3.14159 / (LIFE-2)

MSTOT = 0

MS<sub>1</sub> = 0

MS<sub>2</sub> = MSB

For M = 1 to LIFE

Assumed MS<sub>M</sub> = DELTA x (SIN(((M-1) x INC) - 1.5708) + 1) -  
(SIN(((M-2) x INC) - 1.5708) + 1)) / 2

Input MS<sub>M</sub> or press Return to accept assumed value

MSTOT = MSTOT + MS<sub>M</sub>

Next M

If MSTOT is not equal to 1.0 then print IMPROPER INPUT.

59. For M = 1 to LIFE

For L = 1 to M

CUMMSM = CUMMSM + MSL

Next L

Next M

60. For M = 3 to LIFE

PGRM = ((CUMMSM/CUMMSM-1) - 1)

Next M

61. The program sums the land area of all study areas (GAS) to equal total gross acreage of service area (AT) in acres.

AT = 0

For study area 1 to N

AT = AT + GAS study area

Next N

62. "The total gross acreage of the service area (AT) is estimated to be [display AT value solved above] acres. Enter override value for AT if desired, in acres:"
63. "Select distribution pipeline installation cost correction factor (DISTP) from the following: 1.0 for highly urbanized service area with uncertain existing utility locations in rights-of-way; 0.75 for highly urbanized service area with known utility locations in rights-of-way; 0.50 for moderately urbanized service area; or 0.35 for sparsely urbanized service area. Enter selected DISTP:"
64. "Enter assumed distribution fluid send-out temperature (TD) from 95 to 210OF, in degrees Fahrenheit:" Allow number of subcases entered in Step 46.
65. "The program assumes a 75OF distribution loop return temperature (DISTRT). Enter override value for DISTBRT if desired, in degrees Fahrenheit:" Allow number of subcases entered in Step 46.
66.  $DT = TD - DISTRT$

67. If DT equals or is less than 0, then make user reenter DISTRT using the message: "Reenter distribution return temperature (DISTRT). The temperature you entered is greater than your distribution send-out temperature (TD). You must enter a value lower than your distribution send-out temperature."

68.  $GPM = JP / (500 \times DT)$

Where: GPM = distribution pipeline flow rate, in gpm

500 = conversion of Btu/hr and °F to gpm

DT = usable heat

69.  $LD = 4 \times \text{sq. root of } (AT \times 43,560)$

70. "The program calculates the distribution pipeline length to be [display LD] feet. Enter override value for LD if desired, in feet:" Allow number of cases entered in Step 46.

71.  $HD = LD \times 3/100$

72. "Pumping head (HD) is estimated to be [display HD value solved above] feet. Enter override value for HD if desired, in feet: "

73. "The program assumes pump efficiency (PUMEF) as 70%. Enter override value for PUMEF if desired, as a decimal:"

74.  $PDIST = 3,960 \times PUMEF$

3,960 = conversion of gpm and head into horsepower at 100% efficiency

75.  $CPDIST = (400 \times GPM \times HD / PDIST) \times 10^{-6} \times HI$

Where: CPDIST = total pump capital costs for distribution,  
in million \$

400 = estimated dollar ratio to each horsepower  
of pump size (in 1983 dollars)

GPM = distribution pipeline flow rate in gallons  
per minute

HD = pumping head, in feet

PDIST = conversion factor for gallons per minute and  
lift in feet into horsepower at PUMEF

$10^{-6}$  = conversion to million \$

HI = cost adjustment for inflation since 1983

76. "The distribution pump capital cost (CPDIST) is estimated to be \$ [display CPDIST value solved above] million. Enter

override value for CPDIST if desired, in million \$:"

77. Not used.

78.  $DIAM = CINT[0.49 \times GPM^{**0.38} + 0.5]$

79. If  $TD > 120$  then  $CDP = LD \times [(-1.4 + 6.28 \times DIAM) + (2.88 \times EXP(0.26 \times DIAM))]$   $\times 10^{-6} \times HI$

80. If  $TD < \text{or} = 120$  then  $CDP = LD \times [(0.3 + 1.4 \times DIAM) + (2.57 + 1.7 \times DIAM)] \times 10^{-6} \times HI$

81. Not used.

82. Not used.

83.  $CBLDG = (0.12 + ((GPM / 1000) \times 0.025)) \times HI$

where:

CBLDG = capital cost of central building

0.12 = basic heat exchanger bldg. of 1200 sf at  
\$100/sf construction cost.

1000 = 1000 GPM/heat exchanger

0.025 = incremental construction cost of 250 square  
feet at \$100/SF.

HI = cost adjustment for inflation since 1983

84. "The program estimates the cost of a central heat exchanger and control building at \$[display CBLDG value] million. Enter override value for CBLDG if desired, in million \$:"

85.  $CCS = 0.003 \times JP \times 10^{-6} \times HI$

CCS = heat exchanger cost, in  $\$10^6$

0.003 = cost coefficient from central station facilities and peak load correlation analysis of \$3,000 per 1MBtu of exchanger capacity (based on Klamath Falls, Oregon system adjusted to 1983 dollars)

JP = gross diversified peak service area load adjusted for ultimate market penetration, BTU/HR.

85.1  $HPMP = (1.45 - 0.0584 \times \text{Log}(JP)) \times JP \times 10^{-6} \times HI$

86. If  $(TD + 10)$  is less than or equal to 120°F and  $HPMP > 0$ , then  $CCS = CCS + HPMP$

Where: CCS = heat exchanger with heat pump capital costs in million \$

0.45 = cost coefficient from central heat pump and peak load correlation analysis (in 1983 dollars)

0.0584 = cost coefficient from central heat  
pump and peak load correlation  
analysis (in 1983 dollars)

(TD + 10) = assumes approach temperature of 10°F  
across heat heat exchanger

87.  $CNTRL = CCS \times 1.3$

Where: 1.3 = 20% cost allowance for electrical service  
work and 10% for contingencies.

88.  $CENF = CNTRL + CBLDG$

89. "The central building controls heat exchanger (heat pump  
if less than 121°F) capital costs (CENF) are estimated to be  
\$ [display CENF value solved above] million. Enter  
override value for CENF if desired, in million \$:" Allow  
number of subcases entered in Step 46.

90.  $DISTC = CPDIST + CDP + CENF$

91. "The total capital cost for the distribution system is  
estimated to be \$[display DISTC] million. Enter override  
value for DISTC if desired, in million \$:" Allow number of  
subcases entered in Step 46.

92.  $CDO = [(CDP) \times 0.01] + [(CENF) \times 0.05]$

Where: CDO = initial distribution system maintenance cost, in million \$/yr

0.01 = percent of capital cost assumed to equal annual maintenance for pipelines

0.05 = percent of capital cost assumed to equal annual maintenance for remaining components

93. "The initial maintenance cost for the distribution portion of the system (CDO) is estimated to be \$ [display CDO value solved above] million. Enter override value for CDO if desired, in million \$:" Allow number of subcases entered in Step 46.

94. "Enter cost of electricity (CKW) in \$/kwh:"

95.  $CPC = HD \times GPM \times CKW \times 2.21 \times 10^{-6} / PUMEF$

Where: CPC = initial electrical cost of distribution pumping in  $\$10^6$

$$2.21 = \frac{60 \text{ min/hr} \times 8.33 \text{ lbs/gal} \times 8760 \text{ hrs/yr} \times 1 \frac{\text{kw}}{\text{hp}}}{1,980,000 \frac{\text{ft} \cdot \text{lbs}}{\text{HP} \times \text{hr}}}$$

4.12 = assumed pumping head required per acre for typical distribution pipeline at 100% efficiency

$10^{-6}$  = conversion to million \$

$$96. \quad \text{If } (TD + 10) < 121, \text{ then } CHE = (((JA / 8760) \times 2.57) / \\ (1.55 + (0.035) \times (TD + 10))) \\ \times CKW \times 10^{-6}$$

If  $(TD + 10) = \text{or } > 121$ , then  $CHE = 0$

Where:

$(TD + 10)$  = heat source temperature defined as 10°F  
greater than distribution fluid  
temperature, in °F

121 = minimum temperature assumed for direct-use  
of heat source, in °F

CHE = initial electrical costs for heat pump,  
in million \$/yr

CKW = commercial electric cost in \$/kwh

2.57 = conversion of equation units

$10^{-6}$  = conversion to million \$

1.55 = vertical axis intercept for source water  
temperature and coefficient of performance  
relationship, assuming 120°F send-out  
temperature (Oregon Institute of Technology,  
1978-83)

0.035 = slope for temperature/COP relationship  
(O.I.T.)

IP = weighted average initial market penetration  
rate for service area

97.  $DSTOM = CDO + CHE + CPC$

Where: DSTOM = total initial distribution system operation  
and maintenance cost, in million \$/yr

98. "The distribution system's total initial operation and  
maintenance cost (DSTOM) is estimated to be \$ [display DSTOM  
value solved above] million. Enter override value for DSTOM  
if desired, in million \$:" Allow 5 subcases to be entered.

99. "This completes the Distribution module."

Each of the case results per Step 46 must be carried forward  
for all the following: MS, CUMMS, TD, DISTRT, LD, CENF,  
CDO, DSTOM, DISTCAPCOST.

### MODULE 3

100. "Enter community name:"

101. "Enter date."

102. "Enter service area name:"

103. "Enter case name:"

104. Not used.

105. The program displays the table shown below and the following message: "Typical values for the expected percentage of the total annual load (TTAS) to be met in each month are given below. Enter override values, if desired:"

	<u>Assumed % of Annual Load</u>	<u>Override (as a decimal)</u>	
JAN	14	—	ANPER <sub>1</sub>
FEB	12	—	ANPER <sub>2</sub>
MAR	10	—	ANPER <sub>3</sub>
APR	8	—	ANPER <sub>4</sub>
MAY	6	—	ANPER <sub>5</sub>
JUN	4	—	ANPER <sub>6</sub>
JUL	4	—	ANPER <sub>7</sub>
AUG	4	—	ANPER <sub>8</sub>
SEP	6	—	ANPER <sub>9</sub>

OCT	8	_____	ANPER <sub>10</sub>
NOV	10	_____	ANPER <sub>11</sub>
DEC	<u>14</u>	_____	ANPER <sub>12</sub>
Sum = 100		Sum = 100	

NOTE: If override values are used the sum must still equal 100;  
display error message if not 100.

106. "Select one heat source from the following number:"

Waste Heat	<u>1</u>
Biomass	<u>2</u>
Geothermal	<u>3</u>

CHOICE = 1, 2, or 3

On CHOICE go to 107, 127, 147

Program automatically goes to the subroutine for the heat  
source selected: 1 is Steps 107 through 126; 2 is Steps  
127 through 146; 3 is Steps 147 through 201.

107. "Enter temperature of waste heat (WTEMP) in °F:"

108. "Enter peak heat available from waste source (WP) in  
Btu/hr:"

109. "Enter annual heat available from waste source (WAN) in  
Btu/yr:"

110. "Enter percentage of peak waste heat available by month, as a decimal. Each of the 12 values must be less than or equal to 1.0, and at least one value must equal 1.0:"

JAN \_\_\_\_ WPP(1)  
FEB \_\_\_\_ WPP(2)  
MAR \_\_\_\_ WPP(3)  
APR \_\_\_\_ WPP(4)  
MAY \_\_\_\_ WPP(5)  
JUN \_\_\_\_ WPP(6)  
JUL \_\_\_\_ WPP(7)  
AUG \_\_\_\_ WPP(8)  
SEP \_\_\_\_ WPP(9)  
OCT \_\_\_\_ WPP(10)  
NOV \_\_\_\_ WPP(11)  
DEC \_\_\_\_ WPP(12)

NOTE: Perform check, and if not correctly entered print "Improper entry; repeat percentage of peak heat available by month, as a decimal. Each of the 12 values must be less than or equal to 1.0, and at least one value must equal 1.0."

111. "Enter percentage of annual heat available by month, as a decimal. The 12 values entered must sum to 1.0:"

JAN \_\_\_\_ WAP(1)  
FEB \_\_\_\_ WAP(2)  
MAR \_\_\_\_ WAP(3)

APR \_\_\_\_\_ WAP(4)  
MAY \_\_\_\_\_ WAP(5)  
JUN \_\_\_\_\_ WAP(6)  
JUL \_\_\_\_\_ WAP(7)  
AUG \_\_\_\_\_ WAP(8)  
SEP \_\_\_\_\_ WAP(9)  
OCT \_\_\_\_\_ WAP(10)  
NOV \_\_\_\_\_ WAP(11)  
DEC \_\_\_\_\_ WAP(12)

NOTE: Display error message if sum does not = 100.

112. "Enter the cost, if any, for the waste heat at the source (WCST), in \$/MMBtu (enter 0 if there is no cost):"

113. Program sizes and costs heat exchanger at waste source, in million \$:

$$WEXCH = (WPK \times 0.003 \times 10^{-6})$$

114.  $WEXCHCST = WEXCH \times 1.3 \times HI$

Where: 1.3 = 30% for controls, electrical, and contingency

115. "The capital cost for a waste heat exchanger is estimated to be \$[display WEXCHCST] million. Enter override value for WEXCHCST if desired, in million \$:"

116. "Enter distance from waste heat source to central heat exchanger building (WDIST), in miles:"

117. Enter waste transmission pipeline installation cost correction factor (WPIPK) from following choices: 1.0 for highly urbanized service area with uncertain existing utility locations in rights-of-way; 0.75 for highly urbanized service area with known utility locations in rights-of-way; 0.50 for moderately urbanized service area; or 0.35 for sparsely urbanized service area. Enter selected WPIPK: \_\_\_\_\_

118.  $WGPM = WPK / [500 \times (WTEMP - (TD + 10))]$

If demoninator = 0 then 400 deltatee is substituted

119. If  $WTEMP \geq 120$ , then  $WPCST = 2 \times WDIST \times WPIPK \times [-0.0462 + (0.0197 \times \text{square root of } WGPM)] \times HI$

Where: WPCST = capital cost of waste transmission pipeline, in million \$

2 = sum of supply and return lines

WDIST = transmission pipeline distance, in miles

WPIPK = correction factor for waste transmission pipeline installation costs

-0.0462 = cost efficient from pipeline  
diameter and flow correlation  
analysis (in 1983 dollars)

0.0197 = cost coefficient from pipeline dia-  
meter and flow correlation analysis  
(in 1983 dollars)

120. If WTEMP < 120, then WPCST = 2 x WDIST x WPIPK x [-0.0308 +  
0.0131 x square root of WGPM] x HI

where: -0.0308 = cost coefficient from pipeline diameter  
and flow correlation analysis for heat  
pump systems (in 1983 dollars)

0.0197 = cost coefficient from pipeline diameter  
and flow correlation analysis for heat  
pump systems (in 1983 dollars)

121. "The capital cost of the waste heat transmission pipeline is  
estimated to be \$ [display WPCST]. Enter override value for  
WPCST if desired, in million \$:"

122. Program sums WEXHCST and WPCST to equal total waste heat  
capital cost (WCCST).

123. "The total capital cost of the waste heat system is  
estimated to be \$ [display WCCST] million. Enter override  
value for WCCST if desired, in million \$:" Allow number of  
subcases entered in Step 46.

124. Program calculates annual waste heat O&M costs:

$$WOM = WCCST \times 0.01$$

125. "The initial operation and maintenance cost for the waste heat system is estimated to be \$ [display WOM] million per year. Enter override for WCOM if desired, in million \$/year:"

126. I = 1 to 12

$$WDIFF_I = JP - (WPP(I) \times WPK)$$

If any WDIFF is positive then PKFRAC = (MAX positive WDIFF) x 10<sup>-6</sup> and go to Step 202.1. If all WDIFF are negative go to Step 216.

127. If BIO go to Step 128.

128. "Enter temperature of biomass heat source (BTEMP) in OF:"

129. "Enter peak heat available from biomass source (BPK) in Btu/hr:"

130. "Enter annual heat available from biomass source (BAN) in Btu/yr:"

131. "Enter percentage of peak biomass heat available by month, as a decimal. Each of the 12 values must be less than or equal to 1.0, and at least one value must equal 1.0:"

JAN \_\_\_\_ BPP(1)  
FEB \_\_\_\_ BPP(2)  
MAR \_\_\_\_ BPP(3)  
APR \_\_\_\_ BPP(4)  
MAY \_\_\_\_ BPP(5)  
JUN \_\_\_\_ BPP(6)  
JUL \_\_\_\_ BPP(7)  
AUG \_\_\_\_ BPP(8)  
SEP \_\_\_\_ BPP(9)  
OCT \_\_\_\_ BPP(10)  
NOV \_\_\_\_ BPP(11)  
DEC \_\_\_\_ BPP(12)

NOTE: Perform check, and if not correctly entered print "Improper entry; repeat percentage of peak heat available by month, as a decimal. Each of the 12 values must be less than or equal to 1.0, and at least one value must equal 1.0."

132. "Enter percentage of annual heat available by month, as a decimal. The 12 values entered must sum to 1.0.

JAN \_\_\_\_ BAP(1)  
FEB \_\_\_\_ BAP(2)  
MAR \_\_\_\_ BAP(3)

APR \_\_\_\_ BAP(4)  
MAY \_\_\_\_ BAP(5)  
JUN \_\_\_\_ BAP(6)  
JUL \_\_\_\_ BAP(7)  
AUG \_\_\_\_ BAP(8)  
SEP \_\_\_\_ BAP(9)  
OCT \_\_\_\_ BAP(10)  
NOV \_\_\_\_ BAP(11)  
DEC \_\_\_\_ BAP(12)

NOTE: display error message if sum does not = 1.0

133. "Enter the cost, if any, for the biomass at the source (BCST), in \$/million Btu:"

134. Program sizes and costs biomass boiler, in million \$:

$$\text{BOILER} = 0.00273 \times \text{BPK} \times 10^{-6}$$

135.  $\text{BBOIL} = \text{BOILER} \times 1.3 \times \text{HI}$

Where: 1.3 = 30% allowance for controls, buildings, contingencies.

136. The capital cost for a biomass boiler is estimated to be \$ [display BBOIL]. Enter override value for BBOIL if desired, in million \$:"

137. "Enter distance from biomass heat source to central heat exchanger facility (BDIST), in miles:"

138. "Enter biomass transmission pipeline installation cost correction factor from following choices: 1.0 for highly urbanized service area with uncertain existing utility locations in rights-of-way; 0.75 for highly urbanized service area with known utility locations in rights-of-way; 0.50 for moderately urbanized service area; or 0.35 for sparsely urbanized service area. Enter selected BPIPK:

138.1  $BGPM = BIPK / [500 \times (BBTEMP - (TD + 10))]$

If denominator = 0 then set = to 400 deltatee

139. If  $BBTEMP \geq 120$  then  $BPCST = 2 \times BDIST \times BPIPK \times [-0.0462 + (0.0197 \times \text{square root of } BGPM)] \times HI$

Where: BPCST = capital cost of biomass transmission pipeline, in million \$

BDIST = biomass transmission pipeline distance, in miles

BPIPK = correction factor for biomass pipeline installation costs

-0.0462 = cost efficient from pipeline diameter and flow correlation analysis (in 1983 dollars)

0.0197 = cost coefficient from pipeline diameter  
and flow correlation analysis (in 1983  
dollars)

140. If BBTEMP < 120, then BPCST = 2 x BDIST x BPIPK x [-0.0308 +  
0.0131 x square root of BGPM] x HI

where: -0.0308 = cost coefficient from pipeline diameter  
and flow correlation analysis for heat  
pump systems (in 1983 dollars)

0.0197 = cost coefficient from pipeline diameter  
and flow correlation analysis for heat  
pump systems (in 1983 dollars)

141. "The capital cost of the biomass transmission pipeline is  
estimated to be \$ [display BPCST] million. Enter override  
value for BPCST if desired, in million \$:"

142. BCCST = (BPCST + BBOIL)

143. "The total capital cost for the biomass system is estimated  
to be \$ [display BCCST] million. Enter override value for  
BCCST if desired, in million \$:" Allow number of subcases  
entered in Step 46.

144. Program calculates annual O&M costs using following equation:

$$\text{BIOOM} = \text{BBOIL} \times 0.05$$

145. "The initial operation and maintenance cost for the biomass system is estimated to be \$ [display BIOOM] million. Enter override value for BIOOM if desired, in million \$:"

146. I = 1 to 12

$$\text{BDIFF}(I) = \text{JP} - (\text{BPP}(I) \times \text{BPK})$$

Next I

If any BDIFF is positive then find the MAX positive BDIFF) x 10-6 and go to Step 202.1. If all BDIFF are negative go to Step 216.

147. If GEO was selected then go to Step 148.

148. "Do you want to peak geothermal with conventional fuel? If yes then enter Y; if No then enter N." Equals ANSWER148.

149. If ANSWER148 = N, then JPG = JP

Where: JPG = geothermal portion of gross diversified peak for service area adjusted for ultimate market penetration, in Btu/hr

JP = gross diversified peak service area load adjusted for ultimate market penetration, in Btu/hr

150. If ANSWER148 = Y then GFRAC = 0.5 and go to Step 151; else go to Step 153.

151. "The program assumes that 50% of the peak load will be met by the geothermal resource. Enter override value for GFRAC if desired, as a decimal:"

152. If ANSWER148 = Y then  $JPG = JP \times GFRAC$

153. "Enter the following geothermal data and reliability levels (RL). Select and enter RL values for each geothermal data item from the following: 1.0 for test results from existing well(s) to be used in the project; 0.9 for an estimate based on well(s) in the same production field; 0.8 for an estimate based on well(s) in similar areas; or 0.6 for an estimate based only on surface geological information and literature review:"

Maximum production well flow rate (FLOW) in gpm = \_\_\_\_\_  
(don't accept > 3,000)

Flow rate reliability level (RL1) = \_\_\_\_\_

Wellhead temperature (TEMP) in OF = \_\_\_\_\_

Temperature reliability level (RL2) = \_\_\_\_\_

$GTEMP = TEMP \times RL2$  (GTEMP cannot be <50 or >220)

Depth to production zone from surface (DEPTH) in feet = \_\_\_\_\_  
(don't accept > 10,000)

Production zone reliability level (RL3) = \_\_\_\_\_

Average drilling and casing cost (DRILL) in \$/per foot = \_\_\_\_\_

Drilling cost reliability level (RL4) = \_\_\_\_\_

Static water level below ground level (STATIC) in feet = \_\_\_\_\_

Static water reliability level (RL5) = \_\_\_\_\_

154. Not used.

155. Not used.

156.  $GDEPTH = DEPTH \times (1/RL3)$

Where: GDEPTH = production zone depth adjusted for  
reliability, in feet

157.  $GDRIL = DRILL \times (1/RL4)$

Where: GDRIL = production well drilling and casing costs  
adjusted for reliability, in \$/ft

158.  $GSTAT = STATIC \times (1/RL5)$

Where: GSTAT = static water level below ground level  
adjusted for reliability, in feet

159. Program computes the following (where GEODT equals usable heat or temperature drop across the heat exchanger):

<u>When GTEMP=</u>	<u>GEODT =</u>
220	60
219	60
218	59
217	58
216	57
215	57
214	56
213	55
212	55
211	54
210	53
209	53
208	52
207	51
206	51
205	50
204	49
203	48
202	47
201	46
200	45
199	45
198	44
197	43
196	42
195	41
194	41
193	40
192	39
191	39
190	38
189	37
188	36
187	35
186	34
185	33
184	33
183	32
182	31
181	31
180	
thru	
140	30
139	30
138	29
137	28

<u>When GTEMP=</u>	<u>GEODT =</u>
136	27
135	27
134	26
133	25
132	25
131	24
130	23
129	22
128	21
127	20
126	19
125	19
124	18
123	17
122	17
121	16
120	
thru	
99	40
98	39
97	38
96	37
95	
thru	
91	36
90	35
89	34
88	33
87	32
86	31
85	30
84	
thru	
80	30
79	29
78	28
77	27
76	26
75	25
74	24
73	23
72	22
71	21
70	20
69	19
68	18
67	17
66	16
65	
thru	
59	15
58	14
57	13

When GTEMP=    GEODT =

56	
thru	
54	12
53	11
52	10
51	9
50	8

160. "The geothermal system's usable heat or temperature drop across the heat exchanger (GEODT) is estimated to be [display GEODT value solved above] °F. Enter override value for GEODT if desired, in °F:"

161.  $WELOP = GFLOW \times GEODT \times 500$

Where:     $WELOP$  = maximum energy output per production well, in Btu/hr

500 = conversion factor for gpm and °F to Btu/hr

162.  $PWEL = JPG / WELOP$

Where:     $PWEL$  = total number of production wells required for service area

$JPG$  = geothermal portion of gross diversified peak for service area adjusted for ultimate market penetration, in Btu/hr

NOTE: round  $PWEL$  up to next highest full digit.

163. "The total number of geothermal production wells is estimated to be [display PWEL value solved above] wells. Enter override value for PWEL if desired:"

164.  $IJWEL = INT (PWEL / 2) + 0.99$

Where:  $IJWEL$  = total number of injection wells required  
for service area

2 = ratio of production wells assumed to each  
injection well

NOTE: round  $IJWEL$  up to next highest full digit

165. "The number of geothermal injection wells is estimated to be [display  $IJWEL$  value solved above] wells. Enter override value for  $IJWEL$  if desired:"

166. "Enter number of geothermal replacement wells ( $RPWEL$ ) expected to be required over the life of the project:"

167. "Enter potential number of geothermal dry holes ( $DRHOL$ ) to be drilled over the life of the project:"

168. "Enter expected drawdown in production well ( $GDRDN$ ), in feet:"

169.  $WELLCOST = [(PWEL + RPWEL) + (0.67 \times DRHOL) + (0.75 \times IJWEL)] \times GDEPTH \times GDRIL \times 10^{-6}$

Where:      0.75 = fraction of production well cost assumed  
                 for each injection well (based on less  
                 casing and completion work)

170. "Enter geothermal exploration and land costs, in million \$  
(EXLND):" Allow 5 subcases of input.

171.  $GWCST = EXLND + GWCST$

172. "The total capital cost of geothermal wells over the life  
of the project is estimated to be \$ [display GWCST value  
solved above] million. Enter override value for GWCST if  
desired, in million \$:" Allow number of subcases entered in  
Step 46.

173. "Enter geothermal transmission pipeline right-of-way  
distance (GDIST) from the most favorable geothermal resource  
site to the central heat exchange facility, in miles:"

173.1 If  $GDIST = 0$  then GOTO 176.

174. "Enter geothermal return transmission pipeline right-of-way  
distance (IJDST) from the heat load area to an injection  
site, in miles. Enter "0" if injection is not being used:"

175. "Enter geothermal transmission pipeline installation cost  
correction factor (GPIPCK) from following choices: 1.0 for

highly urbanized service area with uncertain existing utility locations in rights-of-way; 0.75 for highly urbanized service area with known utility locations in rights-of-way; 0.50 for moderately urbanized service area; or 0.35 for sparsely urbanized service area. Enter selected GPIPK:"

176. If  $GTEMP \geq 120$  then  $GEOSUPPLYCOST = GDIST \times GPIPK \times [-0.0462 + (0.0197 \times \text{square root of } GFLOW)] \times HI$

Where:  $GEOSUPPLYCOST$  = capital cost of supply transmission pipeline, in million \$

$GDIST$  = supply transmission pipeline distance, in miles

$GPIPK$  = correction factor for transmission pipeline installation costs

$-0.0462$  = cost coefficient from pipeline diameter and flow correlation analysis (in 1983 dollars)

$0.0197$  = cost coefficient from pipeline diameter and flow correlation analysis (in 1983 dollars)

177. If  $GTEMP < 120$ , then  $GEOSUPPLYCOST = [GDIST \times GPIPK \times [-0.0462 + (0.0197 \times \text{square root of } GFLOW)]] \times 0.8 \times HI$

Where:  $-0.0308$  = cost coefficient from pipeline diameter and flow correlation analysis for heat pump systems (in 1983 dollars)

$0.0197$  = cost coefficient from pipeline diameter and flow correlation analysis for heat pump systems (in 1983 dollars)

The program assumes that transmission pipeline is insulated steel directly buried in soil that does not require drilling or blasting, and that pavement must be removed and replaced for trenching.

$$178. \text{GEORETRNCOST} = 0.8 \times [\text{IJDST} \times \text{GPIPK} \times [-0.0462 + (0.0197 \times \text{square root of GFLOW})]] \times \text{HI}$$

Where:  $\text{GEORETRNCOST}$  = capital cost of return transmission pipeline

$\text{IJDST}$  = return transmission pipeline distance, in miles

$\text{GPIPK}$  = correction factor for transmission pipeline installation costs

$0.8$  = correction for uninsulated pipe cost difference

$$179. \text{GPCST} = \text{GEOSUPPLYCOST} + \text{GEORETRNCOST}$$

180. "The geothermal supply and return transmission pipeline capital cost is estimated to be \$ [display value GPCST solved above] million. Enter override value for GPCST if desired, in million \$:"

180.1 If GSTAT >0 then GOTO 186.

181. "Is the geothermal resource artesian: Yes or No"

182. If NO then go to Step 186.

183. If YES then "Enter artesian pressure at wellhead (ATP), in pounds per square inch:"

184.  $ARTHD = 2.3 \times ATP$

Where: ARTHD = Head in feet

185. Go to Step 188.

186.  $ADJHD = (GSTAT + GDRDN) + [((GDIST + IJDST) \times (5280/100) \times 2) \times 1.5]$

The constant "2" is equal to an average distribution pressure loss of 2 feet of head per 100 feet of run; and the constant 1.5 is a 50% multiplier of linear pipe head loss to account for valve, fitting, and heat exchanger losses.

187. Go to Step 190.

188.  $ADJHD = [(GDIST + IJDST) \times (5280/100) \times 2 \times 1.5] - ARTHD$

189. If ADJHD is negative print: "Artesian pressure is sufficient to permit service without a wellhead pump." Go to Step 195. If ADJHD is positive go to Step 190.

190. "Pumping head is estimated to be [display ADJHD value solved above] feet. Enter override value for ADJHD if desired, in feet:"

191. "The program assumes a pump efficiency of 70% (GPEF). Enter override value for GPEF if desired, as a decimal:

192.  $GPPOW = 3,960 \times GPEF$

3,960 = conversion of gpm and head into horsepower at 100% efficiency

193.  $PUCST = ((400 \times GFLOW \times ADJHD / GPPOW) \times PWEL) \times 10^{-6} \times HI$

Where: PUCST = total pump capital costs for geothermal system in million \$

400 = estimated dollar ratio to each horsepower of pump size (in 1983 dollars)

GFLOW = maximum geothermal production well flow rate in gallons per minute

ADJHD = adjusted pumping head, in feet

GPPOW = conversion factor for gallons per minute  
and lift in feet into horsepower at  
GPEF

$10^{-6}$  = conversion to million \$

194. "The geothermal pump capital cost is estimated to be \$  
[display PUCST value solved above] million. Enter override  
value for PUCST if desired, in million \$:"

195.  $GLF = (JA / JPG) / 8,760$

Where: GLF = geothermal load factor for service area

JA = total annual service area load adjusted for  
ultimate market penetration, in Btu/yr

JPG = alternate heat source portion of gross  
diversified peak for service area adjusted  
for ultimate market penetration, in Btu/hr

8,760 = annual hours

196.  $CPE = [(2.79 \times GFLOW \times ADJHD \times GLF \times CKW) \times PWEL] \times IP \times 10^{-6} \times HI$

Where: CPE = initial cost of electricity for geothermal  
production and transmission pumping, in  
million \$/yr

2.79 = cost coefficient from cost/load correlation  
analysis (adapted from Lienau, 1981,  
and adjusted to 1983 dollars)

GFLOW = production well maximum flow rate adjusted  
for reliability, in gpm

ADJHD = adjusted pumping head in feet

GLF = geothermal load factor for service area

CKW = commercial electrical costs in \$/kwh

PWEL = total number of production wells required  
for service area

IP = weighted average initial market penetration  
rate for service area

$$197. \text{CRO} = \text{CPE} + (3,000 \times \text{PWEL} \times 10^{-6}) \times \text{HI}$$

Where: CRO = initial geothermal well operation and main-  
tenance costs in million \$/yr

3,000 = annual allowance for production and  
injection well maintenance, in 1983 dollars

$$198. \text{GCCST} = (\text{GWCST} + \text{GPCST} + \text{PUCST}) \times 1.2$$

Where: GCCST = Total geothermal capital costs

1.2 = 20% allowance for controls and contin-  
gencies

199. "The total capital cost for the geothermal system is estimated to be \$ [display GCCST]. Enter override value for GCCST if desired, in million \$:" Allow number of subcases per Step[ 46.

200.  $GEOOM = CRO + (0.01 \times GPCST) + (0.05 \times PUCST)$

201. "The initial geothermal system operation and maintenance cost is estimated to be \$ [display GEOOM value solved above] million. Enter override value for GEOOM if desired, in million \$:"

202. If ANSWER148 = N go to Step 216; else go to Step 203.

202.1 "Do you wish to peak biomass or waste heat with conventional fuel? Yes\_\_\_ No\_\_\_" If Yes go to Step 203, if No go to Step 216.

203. "Select type of peaking boiler:"

Electric \_\_\_\_\_ (then PBOIL = 0.5)

Fossil \_\_\_\_\_ (then PBOIL = 1)

204. If GEO then  $PFRAC = [(1 - GFRAC) \times JP \times 10^{-6}]$

If WASTE then  $PFRAC = \text{MAX of } WDIFF \text{ from Step 126}$

If BIO then  $PFRAC = \text{MAX of } BDIFF \text{ from Step 146}$

205.  $PBCST = PBOIL \times 0.00273 \times (PFRAC) + 0.025 \times HI$

Where: PBCST = capital cost of peaking boiler, in  
million \$

0.00273 = cost coefficient from cost and boiler  
capacity correlation analysis  
(adapted from Lienau, 1981, and  
adjusted to 1983 dollars)

0.025 = cost allowance for boiler space in  
central building (1983 dollars)

206. "The capital cost of a conventional peaking boiler is  
estimated to be \$ [display PBCST value solved above]  
million. Enter override value for PBCST if desired, in  
million \$:" Allow number of subcases of input per Step 46.

207. If PEAKBOILK = 0.5 then go to Step 208; if PEAKBOILK = 1.0  
then go to Step 210.

208. If PBCST > 0 and electricity was chosen (PEAKBOILK = 0.5)  
then convert CKW to \$/MMBtu using  $CPF = CKW \times 293$ .

209. "The cost of electrical peaking is estimated to be \$  
[display CPF] per million Btu. Enter override value for  
CPF if desired, in \$/million Btu:" Allow 5 subcases of  
input. Go to Step 211.

210. If  $PBCST > 0$  and fossil fuel was chosen ( $PEAKBOILK = 1.0$ ) then: "Enter purchased cost of peaking fuel (CPF) in \$/million Btu:" Allow 5 subcases of input.

211. If  $PEAKBOILK = 0.5$  then  $BOILEFF = 1.0$ ; if  $PEAKBOILK = 1.0$  then  $BOILEFF = 0.65$ .

212. If  $JPG$  does not equal  $JP$ , then  $PKFUELCOST = [10-12 \times JA \times 0.05 \times CPF] \times IP/BOILEREFF$

Where:  $PKFUELCOST$  = first year cost of peaking fuel, in million \$/yr

$10-12$  = conversion for million dollars and MBtu's

$0.05$  = assumed percent of system's annual operation that peaking fuel is used

$CPF$  = purchased unit cost of peaking fuel, in \$/MBtu

213. If  $JPG = JP$ , then  $PKFUELCOST = 0$

214.  $PKBOILMAINT = PBCST \times 0.05$

215.  $PKBOILOM = PKBOILMAINT + PKFUELCOST$

216. "The program assumes a 20% capital cost allowance for engineering and contingencies (ENG) for the distribution and heat source systems. Enter an override value for ENG if desired, as a decimal:"

217.  $SCCST = (DISTC + WCCST + BCCST + GCCST + PBCST) \times (1 + ENG)$

Where: SCCST = total system capital cost, in  
million \$

NOTE: Two heat sources not being used must equal 0.

218. "The total capital cost of the system is estimated to be \$ [display SCCST value solved above] million. Enter override value for SCCST if desired, in million \$:" Allow number of subcases of input per Step 46.

219.  $SMOM = DSTOM + WOM + BIOOM + GEOOM + PKBOILOM.$

220. "The system's total initial operation and maintenance cost is estimated to be \$ [display SMOM value solved above] million. Enter override value for SMOM if desired, in million \$:" Allow number of subcases of input per Step 46.

221. "This completes the Heat Source module, press any key and RETURN to return to Menu and/or Module 7."

#### MODULE 4

222. "Enter community name:"

223. "Enter service area name:"

224. "Enter case name:"

225. "Enter date:" Print Community Name, Service Area Name, Case Name, and Date in upper corner of every output page.

226. Not used.

227. "Enter general economic inflation rate as a decimal:"

First 5 years \_\_\_\_\_ (GINF(1))

Remaining years \_\_\_\_\_ (GINF(2))

228. "Enter electricity cost inflation rate as a decimal:"

First 5 years \_\_\_\_\_ (EINF(1))

Remaining years \_\_\_\_\_ (EINF(2))

229. Reference Step 106, on CHOICE go to Step 231, 234, 237.

230. Not used.

231. Display following questions:

"Enter BCST inflation rate for first 5 years, as a decimal:  
\_\_\_\_\_ (BINF(1))"

"Enter BFC inflation rate for remaining years, as a decimal:  
\_\_\_\_\_ (BINF(2))"

232. Not used.

233. Not used.

234. Display following questions:

"Enter WCST inflation rate for first 5 years, as a decimal:  
\_\_\_\_\_ (WINF(1))"

"Enter WCST inflation rate for remaining years, as a  
decimal: \_\_\_\_\_ (WINF(2))"

235. Not used.

236. Not used.

237. "IF PGCST = 0 GOTO 238 and enter cost inflation rate for  
peaking fuel as a decimal (enter NA if peaking is not being  
used):"

First 5 years \_\_\_\_\_ (PINF(1))

Remaining years \_\_\_\_\_ (PINF(2))

238. "Enter system ownership (SYSOWN) as PUBLIC or PRIVATE:" If PRIVATE then go to Step 239, if PUBLIC go to Step 245. On SYSOWN GOTO 245, 239.

239. When PRIVATE is entered display following list of questions:

"Percent of capital cost for insurance, as a decimal  
\_\_\_\_\_ (INS)"

"Inflation rate for insurance cost, as a decimal:"

First 5 years \_\_\_\_\_ (IINF(1))

Remaining years \_\_\_\_\_ (IINF(2))

"Percent of capital cost for property taxes, as a decimal  
\_\_\_\_\_ (PTX)"

"Inflation rate for property tax, as a decimal:"

First 5 years \_\_\_\_\_ (TINF(1))

Remaining years \_\_\_\_\_ (TINF(2))

"Combined rate of federal & state income taxes, as a decimal  
\_\_\_\_\_ (TXRT)"

"Required rate of return on equity, as a decimal  
\_\_\_\_\_ (ROR)"

"Are alternate energy tax incentives applicable:"

Yes \_\_\_\_ No \_\_\_\_

240. If NO then ETC and DPL = 0 and go to Step 243. If YES then display following if BIO or WASTE was selected in Module 3, or go to Step 241 if GEO was selected.

"Biomass and/or waste heat energy tax credit: Yes \_\_\_\_  
No \_\_\_\_ (if YES then ETCBW = 0.10)

241. If GEO and GTEMP > 121 then ETCG = 0.15 and DPL = 0.15, and display following list (If GEO was not selected, or if GTEMP < 121 then ETCG and DPL = 0):

"Percent of district heat sales price attributed  
to geothermal wellhead operations, as a decimal  
\_\_\_\_\_ (WHD)"

"Percent of well cost that is intangible, as a decimal  
\_\_\_\_\_ (IDR)"

242.  $IDC = IDR \times GWEST$

243.  $ETC = [ETCG \times (GCCST - IDC)] + [ETCBW \times (BCCST + WCCST)]$

244.  $DEPR = [(SCCST - IDC) \times 0.95] - (ETC/2)$

244.1 GOTO 246.

245. If PUBLIC then display following list of questions:

"Percent of capital cost for insurance, as a  
decimal \_\_\_\_\_ (INS)"

"Inflation rate for insurance cost, as a decimal:"

First 5 years \_\_\_\_\_ (IINF(1))

Remaining years \_\_\_\_\_ (IINF(2))

246. "Of the \$ [display SCCST value] million in total capital  
cost for the system, enter the amount to be debt financed  
(DEBT) in million \$:"

247. "Enter interest rate on DEBT as a decimal (INTRT). Enter  
NA if there is no debt financing:"

247.1 Loop thru the number of subcases from Step 46 by setting  
the singular variables, in Module 4 below to each set of  
subcase cost variables computed in Module 2 and 3. For  
SUBCASE = 1, #.

Where: # = SUBCASE count in 46.

248. "Enter proposed district heat sales price (PSP) in \$/million  
Btu:"

249. Program continues to Steps 250 and beyond, and loops back to Step 248 if insufficient SP is entered, after displaying message shown at Steps 257, 259, 261, or 263. Program solves for each subcase entered in Step 46.

250.  $SP(2) = PSP \times (1 + GINF(1)) \times 10^{-6}$

For I = 2 to 5

$SP(I + 1) = SP(I) \times (1 + GINF(1))$

Next I

For I = 6 to LIFE

$SP(I + 1) = SP(I) \times (1 + GINF(2))$

Next I

Where: SP = heat sales price, in \$/MBtu (3rd letter, B through \_, denotes second through final year of LIFE)

GINF = economic inflation rate

251.  $FYS(2) = JAY \times 10^{-6}$

Where: FYS(2) = initial annual heat sales, in MBtu/yr

JAY = total annual service area load adjusted for initial market penetration, in Btu/yr (JAY is used only to initiate the iteration calculation described below) the final FYS(2) value may not equal JAY)

252. CGC = SCCST and CGO = SMOM

Possible return from 257.

253. For I = 2 to LIFE - 1

FYS(I + 1) = FYS(I) x (1 + PGR(I + 1))

Next I

Where: PGR = annual market penetration growth rate over  
the project's YEARS OF SALES as a decimal

254.  $TAP = DEBT / ((1 - (1 / (1 + INTRT)^{LIFE})) / INTRT)$

Where: TAP = total annual payment on debt including  
principal and interest in million \$

DEBT = amount of total capital cost to be debt  
financed, in million \$

INTRT = interest rate on debt

LIFE = life of project, in years (up to 25)

\*\* = raised to the power

255.  $UPB(1) = DEBT - [TAP - (INTRT \times DEBT)]$

For I = 2 to LIFE

$UPB(I) = UPB(I - 1) - [TAP - (INTRT \times UPB(I))]$

Next I

Where: UPB = unpaid principal balance on debt

The program will show a negligible unpaid balance in the final year due to rounding in this equation.

255.1 If DEBT > 0 and PRIVATE was entered at Step 238 go to Step 256. If DEBT > 0 and PUBLIC go to Step 258. If DEBT = 0 and PRIVATE go to Step 260. If DEBT = 0 and PUBLIC go to Step 262.

256. If DEBT > 0 and user enters PRIVATE at Step 238 program calculates following life-cycle costs:

Note: All of the following spread sheets are examples of 10-year project LIFE; a 25-year project LIFE will extend accordingly, with the last letter in annually changing values going to "Y".

A		B
		PUMPING
1	YEAR	ELECTRICITY
2		EXPENSE
3		
4		
5		(CPE + CHE + CPC)
6		
7	1	
8	2	B5 x (1 + EINF(1))
9	3	[(B5 x PGR(3)) + B8] x (1 + EINF(1))
10	4	[(B5 x PGR(4)) + B9] x (1 + EINF(1))
11	5	[(B5 x PGR(5)) + B10] x (1 + EINF(1))
12	6	[(B5 x PGR(6)) + B11] x (1 + EINF(1))
13	7	[(B5 x PGR(7)) + B12] x (1 + EINF(2))
14	8	[(B5 x PGR(8)) + B13] x (1 + EINF(2))
15	9	[(B5 x PGR(9)) + B14] x (1 + EINF(2))
16	10	[(B5 x PGR(10)) + B15] x (1 + EINF(2))

C

PEAKING  
FUEL  
EXPENSE

(CPA)

```
1
2
3
4
5
6
7
8 C5 x (1 + PINF(1))
9 [(C5 x PGR(3)) + C8] x (1 + PINF(1))
10 [(C5 x PGR(4)) + C9] x (1 + PINF(1))
11 [(C5 x PGR(5)) + C10] x (1 + PINF(1))
12 [(C5 x PGR(6)) + C11] x (1 + PINF(1))
13 [(C5 x PGR(7)) + C12] x (1 + PINF(2))
14 [(C5 x PGR(8)) + C13] x (1 + PINF(2))
15 [(C5 x PGR(9)) + C14] x (1 + PINF(2))
16 [(C5 x PGR(10)) + C15] x (1 + PINF(2))
```

CA

BIOMASS FUEL  
EXPENSE

BCST x (BAN x IP)

```
1
2
3
4
5
6
7
8 CA5 x (1 + BINF(1))
9 [(CA5 x PGR(3)) + CA8] x (1 + BINF(1))
10 [(CA5 x PGR(4)) + CA9] x (1 + BINF(1))
11 [(CA5 x PGR(5)) + CA10] x (1 + BINF(1))
12 [(CA5 x PGR(6)) + CA11] x (1 + BINF(1))
13 [(CA5 x PGR(7)) + CA12] x (1 + BINF(2))
14 [(CA5 x PGR(8)) + CA13] x (1 + BINF(2))
15 [(CA5 x PGR(9)) + CA14] x (1 + BINF(2))
16 [(CA5 x PGR(10)) + CA15] x (1 + BINF(2))
```

CB

WASTE HEAT  
EXPENSE

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16

WCST x (WAN x IP)

CB5 x (1 + WINF(1))  
[(CB5 x PGR(3)) + CB8] x (1 + WINF(1))  
[(CB5 x PGR(4)) + CB9] x (1 + WINF(1))  
[(CB5 x PGR(5)) + CB10] x (1 + WINF(1))  
[(CB5 x PGR(6)) + CB11] x (1 + WINF(1))  
[(CB5 x PGR(7)) + CB12] x (1 + WINF(2))  
[(CB5 x PGR(8)) + CB13] x (1 + WINF(2))  
[(CB5 x PGR(9)) + CB14] x (1 + WINF(2))  
[(CB5 x PGR(10)) + CB15] x (1 + WINF(2))

D

E

PROPERTY  
TAX  
EXPENSE

INSURANCE  
EXPENSE

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16

CGC x PTX

(CGC) x INS

D5 x (1 + TINF(1))	E5 x (1 + IINF(1))
D8 x (1 + TINF(1))	E8 x (1 + IINF(1))
D9 x (1 + TINF(1))	E9 x (1 + IINF(1))
D10 x (1 + TINF(1))	E10 x (1 + IINF(1))
D11 x (1 + TINF(1))	E11 x (1 + IINF(1))
D12 x (1 + TINF(2))	E12 x (1 + IINF(2))
D13 x (1 + TINF(2))	E13 x (1 + IINF(2))
D14 x (1 + TINF(2))	E14 x (1 + IINF(2))
D15 x (1 + TINF(2))	E15 x (1 + IINF(2))

F

G

1	ALL OTHER	DEBT INTEREST
2	O&M	EXPENSE
3	EXPENSES	
4		
5	(CGO) - (B5 + C5)	(INTRT) x (DEBT)
6		
7		G5
8	F5 (1 + GINF(1))	(INTRT) x (UPB(1))
9	F8 (1 + GINF(1))	(INTRT) x (UPB(2))
10	F9 (1 + GINF(1))	(INTRT) x (UPBC(3))
11	F10 (1 + GINF(1))	(INTRT) x (UPB(4))
12	F11 (1 + GINF(1))	(INTRT) x (UPB(5))
13	F12 (1 + GINF(2))	(INTRT) x (UPB(6))
14	F13 (1 + GINF(2))	(INTRT) x (UPB(7))
15	F14 (1 + GINF(2))	(INTRT) x (UPB(8))
16	F15 (1 + GINF(2))	(INTRT) x (UPB(9))

H

I

J

1	INTANGIBLE	TOTAL	GROSS
2	DRILLING	ANNUAL CASH	ANNUAL
3	COSTS	EXPENSES	SALES
4			
5	IDC		(FYS(2))
6			
7	H5	Sum B7 to H7	0
8		Sum B8 to H8	FYS(2) x SP(2)
9		Sum B9 to H9	FYS(3) x SP(3)
10		Sum B10 to H10	FYS(4) x SP(4)
11		Sum B11 to H11	FYS(5) x SP(5)
12		Sum B12 to H12	FYS(6) x SP(6)
13		Sum B13 to H13	FYS(7) x SP(7)
14		Sum B14 to H14	FYS(8) x SP(8)
15		Sum B15 to H15	FYS(9) x SP(9)
16		Sum B16 to H16	FYS(10) x SP(10)

	K	L	M
1	PRE TAX		
2	CASH FLOW	DEPRECIATION	DEPLETION
3			
4			
5		DEPR	DPL
6			
7	J7 - I7		
8	J8 - I8	(L5 x 0.15)	J8 x DPL x WHD
9	J9 - I9	(L5 x 0.22)	J9 x DPL x WHD
10	J10 - I10	(L5 x 0.21)	J10 x DPL x WHD
11	J11 - I11	(L5 x 0.21)	J11 x DPL x WHD
12	J12 - I12	(L5 x 0.21)	J12 x DPL x WHD
13	J13 - I13		J13 x DPL x WHD
14	J14 - I14		J14 x DPL x WHD
15	J15 - I15		J15 x DPL x WHD
16	J16 - I16		J16 x DPL x WHD
10			

	N	O	P
1	TOTAL	NET INCOME	PRE TAX
2	NON-CASH	BEFORE	CASH
3	EXPENSES	TAXES	FLOW
4			
5			
6			
7		K7 - N7	K7
8	L8 + M8	K8 - N8	K8
9	L9 + M9	K9 - N9	K9
10	L10 + M10	K10 - N10	K10
11	L11 + M11	K11 - N11	K11
12	L12 + M12	K12 - N12	K12
13	M13	K13 - N13	K13
14	M14	K14 - N14	K14
15	M15	K15 - N15	K15
16	M16	K16 - N16	K16

	Q	R	S
1	EQUITY	DEBT	INCOME TAX
2		PRINCIPAL	
3		PAYMENT	
4			
5	(CGC - DEBT)		TXRT
6			
7	Q5	TAP - G7	07 x S5
8		TAP - G8	08 x S5
9		TAP - G9	09 x S5
10		TAP - G10	010 x S5
11		TAP - G11	011 x S5
12		TAP - G12	012 x S5
13		TAP - G13	013 x S5
14		TAP - G14	014 x S5
15		TAP - G15	015 x S5
16		TAP - G16	016 x S5

	T	U	V
1	INTANGIBLE	INVESTMENT	ENERGY
2	DRILLING	TAX	TAX
3	COSTS	CREDIT	CREDIT
4			
5	IDC	0.10	ETC
6			
7	T5		
8		U5 x (CGC - IDC)	V5
9			
10			
11			
12			
13			
14			
15			
16			

W

```

1      AFTER TAX
2      CASH FLOW
3
4
5
6
7      P7 - Q7 - R7 - S7 + T7
8      P8 - R8 - S8 + U8 + V8
9      P9 - R9 - S9
10     P10 - R10 - S10
11     P11 - R11 - S11
12     P12 - R12 - S12
13     P13 - R13 - S13
14     P14 - R14 - S14
15     P15 - R15 - S15
16     P16 - R16 - S16

```

X

Y

```

1      AFTER TAX      CUMULATIVE
2      DISCOUNTED   A.T. DIS.
3      CASH FLOW      CASH FLOW
4
5      (1 + ROR)
6
7      W7 / X5         X7
8      W8 / X52        Y7 + X8
9      W9 / X53        Y8 + X9
10     W10 / X54       Y9 + X10
11     W11 / X55       Y10 + X11
12     W12 / X56       Y11 + X12
13     W13 / X57       Y12 + X13
14     W14 / X58       Y13 + X14
15     W15 / X59       Y14 + X15
16     W16 / X510      Y15 + X16 = (VPVT)

```

257. If  $VPVT > 0$ , then program iterates FYS go back to 253 with  $FYSB =$  until  $VPVT = 0$ . GOTO 264. When the program solves for  $FYS(2))$ , if  $FYS(2))$  exceeds JAY the program stops and displays the following statement:

"The program estimates that the amount of first year heat sales (FYS(2)) necessary for successful operations exceeds the service area annual load adjusted for initial market penetration (JAY). In order to complete the study area favorability ratings the user must rerun the program and increase either or both initial market penetration rates (IPS) or heat sales price (SP), if feasible according to local conditions."

The program then returns automatically to Step 248.

258. If  $DEBT > 0$  and user enters PUBLIC at Step 238 program solves same equations for this case except tax and tax credit items are zeroed.

259. Not used.

260. If  $DEBT = 0$  and user enters PRIVATE at Step 238 program calculates same arrays as above but zeros debt-related costs.

261. Not used.

262. If  $DEBT = 0$  and user enters PUBLIC at Step 238 program calculates life-cycle costs with both debt and tax-related items set to zero.

263. Not used.

$$264. \text{ MSA} = \text{FYS}(2) / \text{AT}$$

Where:      MSA = minimum initial year heat sales per land  
                                  area for successful service area operations,  
                                  in MBTU/acre/yr

FYS(2) = first year heat sales, in MBtu/yr

AT = total gross land area of service area, in  
                                  acres

264.1 Print header: STUDY AREA DISTRICT HEATING FAVORABILITY RATINGS

Study Area <u>No.</u>	Favorability <u>Rating</u>	Favorability <u>Ratio</u>	Net Density of Annual Thermal Use <u>(MMBtu/Acre/Yr)</u>	Gross Density of Annual Thermal Use <u>(MMBtu/Acre/Yr)</u>
-----------------------------	-------------------------------	------------------------------	---	---

For I = 1 to STUDYAREA count (ref. Step 47)

$$265. \text{ FS} = \text{NDAS}(I) / \text{MSA}$$

Where:      FS = study area district heating favorability  
                                  ratio

NDAS(I) = net density of annual thermal use in study  
                                  area, in MBtu/acre/yr

This equation is repeated for each study area selected in  
 Step 47. FS is solved for each study area under each  
 subcase entered in Step 46.

266. Program rates favorability ratio (FS) for each study area in each subcase from Step 46 as follows:

If FS is  $> 1.98$ , then the study area FAVRAT = "VERY FAVORABLE"

If FS =  $1.44-1.98$ , then the study area FAVRAT = "FAVORABLE"

If FS =  $0.57-1.43$ , then the study area FAVRAT = "POSSIBLE"

If FS =  $0.34-0.56$ , then the study area FAVRAT = "QUESTIONABLE"

If FS is  $< 0.34$ , then the study area FAVRAT = "UNFAVORABLE"

267. Program prints list of all study areas and their rating title, GDAS value, and FS value as follows:

Print SA(I), FAVRAT, FS, NDAS(I), GDAS(I)

Next I

Completion of loop begun at Step 265. Complete loop from Step 247.1.





## APPENDIX 8

### Electrical Generation Ranking GEORANK Program

- o GEORANK Summary
- o GEORANK Computer Program Listing



## THE GEORANK PROGRAM

The GEORANK computer program was designed to evaluate the development potential for high temperature and direct use geothermal sites in the Pacific Northwest. Specifically, the objective was to identify resources which warrant more detailed investigation. This can save considerable time in the engineering -- economic analyses that will be required for ultimate resource definition. In this fashion, the GEORANK program is a screening tool for geothermal resources.

The program development was centered around a central question. What is the least information that we need to estimate the development potential of a geothermal resource? The characteristics examined represent all the major issues that the assessment team could identify that have major impact on geothermal project potential using commonly available data.

The technique is exploration oriented and is widely applicable to a variety of site types. Thus, the questions that are asked in the course of the program inputs simulate the issues that a geothermal exploration company would likely consider in assessment of a portfolio of resources. We believe that this structure makes the method more useful for a first time survey of geothermal sites in a regional area.

Each variable that is estimated to be important in development potential is assigned a numerical weight in the program which is correlated against a regression variable to determine the fractional development potential for that characteristic. The correlations are usually of a linear or polynomial types. The resulting scores of each variable is then summed for the overall development potential.

GEORANK takes into account both geologic and economic realities inherent in geothermal development. Implicit assumptions are made on the effect of geological data and its implications for project cost. An important facet of the method is that the uncertainties that surround important aspects in the resource determination are identified and approximated. More subjective aspects of system engineering and environmental and institutional aspects are also evaluated. This lends this method of evaluation an important advantage over conventional engineering analysis which typically ignores the importance of such "subjective considerations."

The system is used to rank overall site developability in a relative fashion. Thus, the program results have no meaning apart from a comparative assessment of other geothermal resources. The program is most useful when evaluating a large population of geothermal sites to identify superior ones.

The method is computerized on an MS-DOS based system and is a fast and reliable method of evaluating geothermal sites on a comparative basis. Error checking routines and a simple input-output framework helps with 'user friendliness.' There are two versions, for both high and low temperature geothermal resources. Together they form a useful tool for identification of superior geothermal sites for electricity production or district heating capability. Given availability of the site data, a site can be ranked in less than five minutes.

In the following appendices to the GEORANK program, instructions are provided for use of the program and a guide to a consistent evaluation of uncertainty values for the resource module are included.

## HIGH TEMPERATURE CERTAINTY GUIDELINES

1. Estimated Reservoir Temp: Use resource characterizations from Appendix I and divide minimum reservoir temperature by maximum reservoir temperature.
2. Estimated Drilling Depth:
  1. Drilled to reservoir .9
  2. Drilled to Shallow Depths/Inferred from gradient .6
  3. Inferred from similar geologic area .4
  4. No data .2
3. Age and Type of Volcanism
  1. Young volcanics (under 10,000 yrs.) .9
  2. Intermediate Age volcanics (more than 10,000 less than 100,000 yrs.) .8
  3. Old volcanics (greater than 100,000 yrs.) .7
4. Potential for High Permeability
  1. Mapped Faults and Drilled .9
  2. Mapped Inferred Faults and Drilled .8
  3. Mapped Inferred Faults .6
  4. No data .2
5. Drilling Difficulty
  1. Drilled .9
  2. Inferred from similar Geologic Provinces .7
6. Prospect Areal Extent
  1. Divide the minimum reservoir area (from Appendix I) divided by the maximum reservoir area. If this is unavailable, then use the standard deviation of the estimated reservoir volume divided by the reservoir volume as a proxy for the certainty level.
7. Regional Heat Flow
  1. Measured .9
  2. Inferred or no data .3

## HOW TO USE THE GEORANK PROGRAM

1. Once the computer is turned on with program disk in the disk drive, the monitor display will indicate that the program is being loaded into memory.
2. The program will announce when it is ready. Press the return key to go to the first question.
3. When each screen is displayed, the user will be prompted with a question. For each question, a default value will be displayed. If you like the default, or you do not know the correct answer for the question, then simply press the return key. If you would like to change the answer, then enter the numbers that you would like to enter. Enter no commas in the inputs and remember that all measures are given in SI (metric) units.
4. If you would like a printed copy of the results, then enter yes (1) for that question. Make sure that the printer is connected in slot 1 and the power is turned on.
5. There are some 25 questions in all, with equal numbers dealing with resource, market and environmental/institutional factors. If you are interested in only one category, then accept the defaults for the other questions. If you hold down the return key, questions will be assigned the defaults in succession.
6. After all the inputs have been entered, the program will display the modified scores for each characteristic and the summed total for the resource. A perfect score is 130. This number is followed by the most likely uncertainty and the most likely minimum score which is used for ranking purposes. Compare this number to that for another resource to determine the site with the greatest development potential.
7. Remember, this analytic procedure is only as good as the accuracy of the inputs. Only carefully researched data will ensure consistent and significant results using this research tool.

# HIGH TEMPERATURE RESOURCE RANKING DATA

Site \_\_\_\_\_

Location \_\_\_\_\_

(Town) (County) (State)

Estimate      Certainty Level  
0-1

## I. Resource

1. Estimated Reservoir Temp	_____ C°	_____
2. Estimated Drilling Depth	_____ m	_____
3. Age and Type of Volcanism	_____ 1,2,...,9	_____
4. Potential for High Permeability	_____ 1,2,3	_____
5. Drilling Difficulty	_____ 1,2,3,4	_____
6. Prospect Area Extent	_____ km <sup>2</sup>	_____
7. Heat Flow	_____ mW/m <sup>2</sup>	_____

## II. Market

8. Terrain of Powerline Corridor	_____ 0,1,2,3
9. Resource Site Accessibility	_____ 1,2,3
10. Terrain of Development Site	_____ 1,2
11. Distance to Powerlines	_____ km
12. Distance to Heating Load	_____ km
13. Annual Heating Load	_____ 10 <sup>9</sup> Btu
14. Heat Load Density	_____ 1, 2, 3,

## III. Regulatory/Environmental

15. Land/Resource Management	_____ 1,2,3
16. Percent Leased for Exploration	_____ %
17. Special Regulatory/Environmental Concerns	_____ 0,1,2,3,4
18. Distance to Legally Designated Areas	_____ km
19. Air/Water Pollutants	_____ 0-4+

## Instructions for High Temperature Resource Ranking Data Summary

General: Print or type all entries on the Resource Ranking Data Worksheet. Be sure to specify completely the site and its location. For all estimates and certainty levels enter only numbers. Take care to observe the correct units.

Characteristic: The correct units are indicated. Where units are not specified in the estimate column you will find integers (1,2,3). In such cases enter one of the given numbers.

Certainty Level: Enter only a decimal value between 0 and 1 in the certainty level column for each resource characteristic. The certainty levels should come from the resource assessment sheets for that particular site. Enclosed are certainty estimate guidelines.

### I. RESOURCE:

1. Estimated Reservoir Temp. Enter the estimated reservoir temperature in degrees centigrade.
2. Estimated Drilling Depth Fill in the estimated drilling depth in meters. If there is no information assume a 2000 meter depth and a 0.1 certainty level.
3. Age and Type of Volcanism The correct entry for this characteristic is an integer value 1,2,...9. See the table below.

<u>Rock Type</u>	<u>Age (10<sup>3</sup> Years)</u>	<u>Entry</u>
Basalt	0-15	1
Basalt	15-22	2
Basalt	22-40	3
Andesite	0-50	4
Andesite	50-75	5
Andesite	75-100	6
Rhyolite	0-100	7
Rhyolite	100-500	8
Rhyolite	500-1,000	9

4. Potential for High Permeability Enter a 1,2, or 3 for no fluids, limited faulting or extensive faulting respectively. Alluvium is assumed equivalent to extensive faulting.
5. Drilling Difficulty Rock competence is scored with a 1,2,3 or 4. See the table below for correct entry.

<u>Rock Competence</u>	<u>Entry</u>
Unconsolidated Rocks	1
Incompetent, Pliocene and Younger Volcanics	2
Miocene and Older Volcanics, Lithified Sandstone, Clastics	3
Crystalline Rocks	4

6. Prospect Areal Extent Enter the estimated prospect areal extent in square kilometers.
7. Heat Flow Fill in the site regional heat flow. The units are milliwatts per square meter.

## II. MARKET

8. Terrain of Powerline Corridor The entry for this characteristic ranges from zero to 3 representing the number of Powerline Concerns. Areas of concern are: 1) Terrain: slope > 30%; 2) Limited access; 3) Federal Lands; 4) Agricultural lands; 5) Rivers/ wetlands; 6) Recreational lands.
9. Resource Site Accessibility The values to be entered for site accessibility are 1, 2, or 3. These correspond to roadless, unimproved road, or improved road conditions respectively.
10. Terrain of Development Site. The entry for the characteristic is either a 1 or 2. For terrains with slope < 30% enter a 1; for terrain with slopes > 30% enter 2.
11. Distance to Powerlines Enter the distance in kilometers to powerlines with a capacity greater than 12 kv and less than 230 kv.
12. Distance to Heating Load Values for the distance to heating load is to be entered in kilometers. Maximum distance should be 30 km.
13. Annual Heating Load Enter the estimated value for annual heating load. Units are  $10^9$  BTU. Range of expected entries is 0-2000.
14. Heat Load Density Enter a 1 for urban; 2 for suburban; 3 for rural areas. Use most populous area within 30 km. Rural is defined by populations less than 1,000; suburban is less than 50,000 but greater than 1,000; urban is greater than 50,000.

## III. REGULATORY/ENVIRONMENTAL

15. Land/Resource Management Enter a 1 for mixed management, 2 for federal state or local, or 3 for private land.
16. Percent Leased for Exploration Enter the estimated percent of lands leased for geothermal exploration. For example, if 50% of the land is leased enter 50.
17. Special Regulatory/Environmental Concerns The values to be entered represent the number of regulations or special environmental concerns. Enter 0 for no concerns; 1, 2, 3, etc., indicate other possible total number of concerns.
18. Distance to Legally Designated Areas The distance to designated area is to be given in kilometers. If the response to "Proximity to Governmentally Specified Designated Area" is No then enter 5.
19. Air/Water Concerns This characteristic represents the number of air/water pollutants which are above EPA regulations. Enter 0, 1, 2, ..., 4+. See Table below for EPA levels for listed substances at which point they become a concern.

ENVIRONMENTALLY HAZARDOUS SUBSTANCES

<u>Substance</u>	<u>Standard (ppm)</u>
Barium	1.00
Boron	5.00
H <sub>2</sub> S	0.05*
Rn	10,000 pc.
As	0.05
Hg	0.002
Fluoride	2.4
Silver	0.05
Selenium	0.01
T.D.S.	2000.00
Sulfates	250.00
Cadmium	0.01
Lead	0.05
Zinc	5.00
Iron	0.30
Copper	1.00
Chromium	0.05

All fluids are assumed to be injected back into the reservoir.

The above values are based on risk of drinking water contamination by surface filtration or subsurface injection. The total dissolved solids figure are based on the level above which mitigation measures are needed to prevent equipment problems.

\* Air Quality Standard

# ----- HIGH TEMPERATURE RESOURCE RANKING DATA (DEFAULT VALUES)

SITE: high defaults  
def2 COUNTY, defsta

CHARACTERISTIC	POINTS	UC^2
=====		

## RESOURCE

1) EST.RESERVOR.TEMP	0.51	0.07
2) DRILLING DEPTH	6.37	10.15
3) AGE-TYPE-VOLC.	6.00	9.00
4) POT.HI.PERM.	14.00	49.00
5) DRILLING DIFF.	3.20	2.56
6) AREA EXTENT	0.32	0.03
7) HEAT FLOW	1.97	0.97

SUBTOTAL	32.37	
----------	-------	--

## ENGINEERING

8) TERRAIN PWRLN	3.96	
9) SITE ACCESS	4.00	
10) SITE TERRAIN	4.00	
11) DIST.TO.PWRLN	4.00	
12) DIST.HEAT.LOAD	2.50	
13) ANN.LOAD.DENSITY	0.01	

SUBTOTAL	18.47	
----------	-------	--

## REGULATORY/ENVIRON.

14) LAND/RESOURCE-MGN.	3.20	
15) %LEASED EXPLOR.	00.00	
16) SPEC.REG./ENV.	12.00	
17) DIST.LEG.AREAS	4.94	
18) AIR/WATER	3.75	

SUBTOTAL	23.89	
----------	-------	--

TOTAL	74.73	71.77
=====		

SQRT UC^2= 8.47

MOST LIKELY SCORE	74.73
PROBABLE UNCERTAINTY	8.47
LIKELY MINIMUM SCORE	66.25
NORMALIZED MINIMUM SCORE	.51

HIGH TEMPERATURE RESOURCE INPUT DATA (DEFAULT VALUES)

-----  
SITE: high defaults  
def2 COUNTY, defsta

CHARACTERISTICS EST. CERTAINTY  
=====

RESOURCE  
-----

1)	EST.RSRV.TEMP	100.00 C	0.50
2)	DRILL.DEPTH	2000.00 M	0.50
3)	AGE-TYPE-VOLC.	5.00	0.50
4)	POT.HI.PERM.	3.00	0.50
5)	DRILLING DIFF.	3.00	0.50
6)	AREA EXTENT	2.00 KM^2	0.50
7)	HEAT FLOW	80.00 MW/M^2	0.50

ENGINEERING  
-----

8)	TERRAIN PWRLN	1.00	
9)	SITE ACCESS	3.00	
10)	SITE TERRAIN	1.00	
11)	PWRLN.DIST.	75.00 KM	
12)	LOAD DIST.	5.00 KM	
13)	AN.LD.DENSITY	20.00 10^9 BTU/YR	

REGULATORY/ENVIRON.  
-----

14)	LAND/RESCR.MGN.	1.00	
15)	%LEASED EXPLOR.	00.00 %	
16)	SPEC.REG./ENV.	1.00	
17)	DIST.LEG.AREAS	5.00 KM	
18)	AIR/WATER	1.00	

=====

## ELECTRICAL GENERATION (HIGH TEMPERATURE) SITE RANKING: IDAHO

<u>Rank</u>	<u>Site</u>	<u>Normalized Minimum Score</u>
1.	Raft River	.676
2.	Magic Reservoir	.670
3.	Keystone Hot Springs	.638
4.	White Arrow Hot Springs	.633
5.	Cone Creek/Crane Creek	.632
6.	Big Creek Hot Springs	.628
7.	Sharkey Hot Springs	.614
8.	Guyer Hot Springs	.612
9.	Squaw Creek Hot Springs	.608
10.	Blackfoot Lava Field	.606
11.	Rexburg Caldera	.606
12.	Battle Creek Hot Springs	.601
13.	Carbarton Hot Springs	.597
14.	Maple Grove Hot Springs	.591
15.	White Licks Hot Springs	.585
16.	Barron's Hot Springs	.580
17.	Ben Meeks Well	.575
18.	Indian Creek Hot Springs	.562
19.	Murray Hot Springs	.558
20.	Sunbeam Hot Springs	.537
21.	Boiling Springs	.528
22.	Latty Hot Springs	.526
23.	Riggins Hot Springs	.500
24.	Krigbaum Hot Springs	.498
25.	Deer Hot Springs	.488
26.	Owl Creek	.459
27.	Vulcan Hot Springs	.455
28.	Worside Hot Springs	.446
29.	Bonneville Hot Springs	.424
30.	Island Park Caldera	.419

**ELECTRICAL GENERATION (HIGH TEMPERATURE) SITE RANKING: MONTANA**

<u>Rank</u>	<u>Site</u>	<u>Normalized Minimum Score</u>
1.	Ennis	.676
2.	Silver Star	.602
3.	Marysville Well	.601
4.	Gregson Hot Springs	.593
5.	Jackson Hot Springs	.541
6.	Boulder Hot Springs	.517
7.	Broadwater Hot Springs	.516

**ELECTRICAL GENERATION (HIGH TEMPERATURE) SITE RANKING: OREGON**

<u>Rank</u>	<u>Site</u>	<u>Normalized Minimum Score</u>
1.	Olene Gap	.703
2.	Barry Ranch	.660
3.	Klamath Hills	.645
4.	Glass Buttes	.639
5.	Alvord HS	.639
6.	Klamath Falls Area	.635
7.	Newberry volcano	.632
8.	Vale HS	.627
9.	Lakeview	.615
10.	Hallinan Springs	.598
11.	Neal HS	.597
12.	Trout Creek	.589
13.	Borax Lake	.581
14.	summer Lake	.577
15.	Crump Geyser	.577
16.	Generic High Cascade	.574
17.	Mickey HS	.573
18.	Fisher HS	.565
19.	Crater Lake aRea	.560
20.	Cappy-Burn Butte	.558
21.	Melvin/Three Creek Buttes	.552
22.	Wart Peak Caldera	.546
23.	Devil's Garden	.540
24.	China Hat/East Butte	.534
25.	Bearwallow Butte	.529
26.	Mitchell Butte	.520
27.	Diamond Craters	.518
28.	Four Craters	.517
29.	McDermott Area	.515
30.	Cropp HS	.515
31.	Little Valley Area	.513
32.	Mt. Hood	.512
33.	Crane HS	.510
34.	Weberg HS	.506
35.	Squaw Ridge	.506
36.	Mt. McLoughlin	.503
37.	Blue Mountain HS	.501
38.	Beulah HS	.501
39.	Umpqua	.497
40.	Jackles Butte	.495
41.	Quartz Mountain	.494
42.	Frederick Butte	.490
43.	O.J. Thomas Well	.488
44.	Austin HS	.480
45.	Luce HS	.469
46.	Cougar Peak	.462
47.	Bigelow	.454
48.	Foley HS	.449
49.	Wall Creek HS	.443
50.	Breitenbush HS	.437

**ELECTRICAL GENERATION (HIGH TEMPERATURE) SITE RANKING: OREGON  
(Continued)**

<u>Rank</u>	<u>Site</u>	<u>Normalized Minimum Score</u>
51.	Medical HS	.425
52.	McCredie HS	.411
53.	Kahneeta HS	.405
54.	Belknap HS	.403
55.	Rustler Peak	.396
56.	Jordan Craters	.369

**ELECTRICAL GENERATION (HIGH TEMPERATURE) SITE RANKING: WASHINGTON**

<u>Rank</u>	<u>Site</u>	<u>Normalized Minimum Score</u>
1.	Mt. Baker	.643
2.	Mt. Adams	.583
3.	Puny Creek Basalt	.572



GEORANK

Computer

Program

Listing



```

1 REM 4 Nov 84 JDM
2 PRINT FRE(0)
5 A = 20
10 DIM T2(A),X(A),F(A),U(A)
20 DIM V(A),S(A),UC(A),C(A)
40 DEF FN R(X) = (INT (X * 100 + .5)) / 100
45 DEF FN S(X) = (INT (X * 1000 + .5)) / 1000
70 PRINT "WELCOME TO . . ."
80 PRINT : PRINT
90 PRINT "          GEORANK": PRINT
100 PRINT : PRINT
110 PRINT "GEOTHERMAL RESOURCE ASSESSMENT MODEL"
120 PRINT : PRINT : PRINT
130 GOSUB 7140
150 GOSUB 19600
160 PRINT "*** MENU/ GEORANK PROGRAM ***"
170 PRINT
190 GOSUB 19600
200 PRINT "1) LOW TEMPERATURE RESOURCE"
210 PRINT "2) HIGH TEMPERATURE RESOURCE"
220 PRINT "3) QUIT"
230 HI = 3:LO = 1:CV = 2
240 GOSUB 39200:CH = CV
250 IF CH = 1 THEN 6650
260 IF CH = 2 THEN 6860
270 IF CH = 3 THEN 50000
310 GOSUB 21375: PRINT "RESOURCE NAME":
320 GOSUB 19700
330 PRINT "**RESOURCE MODULE**"
390 GOSUB 21375: PRINT "ESTIMATED RESERVOIR TEMP.- C":
400 HI = 500:LO = 0:CV = 1E
410 GOSUB 39200:TE = CV
420 GOSUB 5290
430 GOSUB 21375: PRINT "CERTAINTY/TEMP.":
440 HI = 100:LO = 0:CV = CT
450 GOSUB 39200:C(1) = CV
470 GOSUB 21375: PRINT "ESTIMATED DRILLING DEPTH- METERS":
480 HI = 10000:LO = 0:CV = DD
490 GOSUB 39200:DD = CV
500 GOSUB 5360
510 GOSUB 21375: PRINT "CERTAINTY, DRILLING DEPTH":
520 HI = 100:LO = 0:CV = CT
530 GOSUB 39200:C(2) = CV
550 GOSUB 21375: PRINT " AGE AND TYPE OF VOLCANISM":
560 PRINT
570 PRINT " 1) BASALT: 0-15 MILL. YEARS"
580 PRINT " 2) BASALT: 15-22 MILL. YEARS"
590 PRINT " 3) BASALT: 22-40 MILL. YEARS"
600 PRINT " 4) ANDESITE: 0-50 MILL. YEARS"
610 PRINT " 5) ANDESITE: 51-75 MILL. YEARS"
620 PRINT " 6) ANDESITE: 76-100 MILL. YEARS"
630 PRINT " 7) RHYOLITE: 0-100 MILL. YEARS"
640 PRINT " 8) RHYOLITE: 100-500 MILL. YEARS"
650 PRINT " 9) RHYOLITE: 500- 1,000 MILL. YEARS"
660 PRINT "10) NON-VOLCANIC"
670 HI = 10:LO = 0:CV = AG

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680 GOSUB 39200:AGE = CV
690 IF AGE = 1 THEN Y = 1!
700 IF AGE = 2 THEN Y = .5
710 IF AGE = 3 THEN Y = .23
720 IF AGE = 4 THEN Y = 1!
730 IF AGE = 5 THEN Y = .5
740 IF AGE = 6 THEN Y = .25
750 IF AGE = 7 THEN Y = 1!
760 IF AGE = 8 THEN Y = .5
770 IF AGE = 9 THEN Y = .25
780 IF AGE = 10 THEN Y = 0!
790 GOSUB 8060
800 GOSUB 21375: PRINT "CERTAINTY/VOLCANICS":
810 HI = 100:LO = 0:CV = CT
820 GOSUB 39200:C(3) = CV
840 GOSUB 21375: PRINT "POTENTIAL FOR HI.PERMEABILITY":
850 PRINT
860 PRINT "1) NO FAULTING"
870 PRINT "2) LIMITED FAULTING"
880 PRINT "3) EXTENSIVE FAULTING"
890 HI = 3:LO = 0:CV = PE
900 GOSUB 39200:PE = CV
910 IF PE = 1 THEN Y = 0
920 IF PE = 2 THEN Y = .5
930 IF PE = 3 THEN Y = 1!
940 GOSUB 8060
950 GOSUB 21375: PRINT "CERTAINTY/PERMEABILITY":
960 HI = 100:LO = 0:CV = CT
970 GOSUB 39200:C(4) = CV
990 GOSUB 21375: PRINT "DRILLING DIFFICULTY":
1000 PRINT
1010 PRINT "1) UNCONSOLIDATED ROCKS"
1020 PRINT "2) YOUNG VOLCANICS"
1030 PRINT "3) OLDER VOLCANICS"
1040 PRINT "4) CRYSTALLINE ROCKS"
1050 HI = 4:LO = 1:CV = DF
1060 GOSUB 39200:DF = CV
1070 IF DF = 1 THEN Y = .3
1080 IF DF = 2 THEN Y = .35
1090 IF DF = 3 THEN Y = .8
1100 IF DF = 4 THEN Y = 1!
1110 GOSUB 8060
1120 GOSUB 21375: PRINT "CERTAINTY/DRILLING DIFF.":
1130 HI = 100:LO = 0:CV = CT
1140 GOSUB 39200:C(5) = CV
1160 GOSUB 21375: PRINT "PROSPECT AREAL EXTENT (IN 2)":
1170 HI = 200:LO = 0:CV = PA
1180 GOSUB 39200:PA = CV
1190 GOSUB 5460
1200 GOSUB 21375: PRINT "CERTAINTY/AREA":
1210 HI = 100:LO = 0:CV = CT
1220 GOSUB 39200:C(6) = CV
1240 GOSUB 21375: PRINT "HEAT FLOW (MW/M 2)":
1250 HI = 500:LO = 0:CV = HF
1260 GOSUB 39200:HF = CV
1270 GOSUB 5500

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1280 GOSUB 21375: PRINT "CERTAINTY/HEAT FLOW":
1290 HI = 100:LO = 0:CV = CT
1300 GOSUB 39200:CT(7) = CV
1320 PRINT "***ENGINEERING MODULE**"
1330 PRINT "POWERLINE TERRAIN CONCERNS"
1340 HI = 10:LO = 0:CV = TC
1350 GOSUB 39200:TC = CV
1360 IF TC = 0 THEN Y = 1!
1370 IF TC = 1 THEN Y = .66
1380 IF TC = 2 THEN Y = .33
1390 IF TC = 3 THEN Y = 0
1400 GOSUB 8060
1420 PRINT "RESOURCE SITE ACCESSIBILITY "
1440 PRINT "1) LIMITED ACCESS"
1450 PRINT "2) UNIMPROVED ROAD"
1460 PRINT "3) ALL WEATHER ROAD"
1470 HI = 3:LO = 0:CV = RS
1480 GOSUB 39200:RS = CV
1490 IF RS = 1 THEN Y = 0
1500 IF RS = 2 THEN Y = .5
1510 IF RS = 3 THEN Y = 1!
1520 GOSUB 8060
1540 PRINT "TERRAIN OF DEVELOPMENT SITE"
1560 PRINT "1) SLOPE < 30 DEGREES"
1570 PRINT "2) SLOPE > 30 DEGREES"
1580 HI = 2:LO = 1:CV = TD
1590 GOSUB 39200:TD = CV
1600 IF TD = 1 THEN Y = 1
1610 IF TD = 2 THEN Y = 0
1620 GOSUB 8060
1640 GOSUB 21375: PRINT "DIST.TO POWERLINES-KM":
1650 HI = 300:LO = 0:CV = PW
1660 GOSUB 39200:PW = CV
1670 GOSUB 5570
1690 GOSUB 21375: PRINT "DISTANCE TO HEATING LOAD (KM)":
1700 HI = 100:LO = 0:CV = HL
1710 GOSUB 39200:HLD = CV
1720 GOSUB 5600
1740 GOSUB 21375: PRINT "HEAT LOAD DENSITY":
1750 HI = 3:LO = 1:CV = DN
1760 PRINT
1770 PRINT "SELECT ONE OF THE FOLLOWING SUBROUTINES:": PRINT : PRINT
1780 PRINT "1) URBAN"
1790 PRINT "2) SUBURBAN"
1800 PRINT "3) RURAL"
1810 GOSUB 39200:DN = CV
1820 IF DN = 1 THEN GOSUB 1850
1830 IF DN = 2 THEN GOSUB 1900
1840 IF DN = 3 THEN GOSUB 1950
1850 GOSUB 21375: PRINT "URBAN HEATING LOAD-10^6 BTU/YR":
1860 HI = 5000:LO = 0:CV = UD
1870 GOSUB 39200:UD = CV
1880 GOSUB 5650
1890 GOTO 2050
1900 GOSUB 21375: PRINT "SUBURBAN HEATING LOAD-10^6 BTU/YR":
1910 HI = 5000:LO = 0:CV = SD

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1920 GOSUB 39200:SD = CV
1930 GOSUB 5680
1940 GOTO 2050
1950 GOSUB 21375: PRINT "RURAL HEATING LOAD-10**9 BTU/YR":
1960 HI = 5000:LO = 0:CV = RD
1970 GOSUB 39200:RD = CV
1980 GOSUB 5710
1990 GOTO 2050
2050 PRINT "***REGULATORY/ENVIRONMENTAL MODULE**"
2060 PRINT "LAND/RESOURCE MANAGEMENT"
2070 PRINT "1) MIXED"
2080 PRINT "2) FED./STATE/LOCAL"
2090 PRINT "3) PRIVATE"
2100 HI = 3:LO = 0:CV = LR
2110 GOSUB 39200:LRM = CV
2120 IF LRM = 1 THEN Y = .4
2130 IF LRM = 2 THEN Y = .7
2140 IF LRM = 3 THEN Y = 1!
2150 GOSUB 8060
2170 GOSUB 21375: PRINT "PERCENT LEASED FOR EXPLORATION":
2180 HI = 100:LO = 0:CV = PLE
2190 GOSUB 39200:PLE = CV
2200 GOSUB 5750
2220 PRINT " NO.EVR./REG. CONCERN":
2230 HI = 10:LO = 0:CV = EV
2240 GOSUB 39200:EV = CV
2250 IF EV = 0 THEN Y = 1!
2260 IF EV = 1 THEN Y = .75
2270 IF EV = 2 THEN Y = .5
2280 IF EV = 3 THEN Y = .25
2290 IF EV = 4 THEN Y = 0!
2300 GOSUB 8060
2320 PRINT " DISTANCE/LEGALLY DESIGNATED AREAS":
2330 HI = 200:LO = 0:CV = DL
2340 GOSUB 39200:DL = CV
2350 GOSUB 5790
2370 PRINT " NO. AIR/WATER CONCERNS":
2380 HI = 10:LO = 0:CV = AW
2390 GOSUB 39200:AW = CV
2400 IF AW = 0 THEN Y = 1!
2410 IF AW = 1 THEN Y = .75
2420 IF AW = 2 THEN Y = .5
2430 IF AW = 3 THEN Y = .25
2440 IF AW = 4 THEN Y = 0!
2450 GOSUB 8060
2560 FOR O = 1 TO 20
2570 S(O) = A(O) * F(O)
2580 NEXT O
2610 FOR H = 1 TO 20
2620 ST = S(OH) + ST
2630 NEXT H
2680 GOSUB 8210
2680 PRINT "*** OUTPUT MENU-HI TEMP.***"
2690 GOSUB 19000
2750 GOSUB 39200:PR = CV
2760 IF PR = 1 THEN GOSUB 8880
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2770 IF RP = 1 THEN GOSUB 1900
2780 IF RP = 3 THEN GOTO 1500
2800 GOTO 1500
2840 ZZ = 0
2850 GOSUB 21375: PRINT "RE-ENTER VALUE":
2860 GOSUB 19700
2870 PRINT "**RESOURCE MODULE**"
2880 PRINT "ENTER TERM OF FILLING":
2900 HI = 500:LO = 0:CV = 15
2910 GOSUB 39200:TMF = CV
2920 GOSUB 5900
2930 GOSUB 21375: PRINT "CERTAINTY/FILLING TERM":
2940 HI = 100:LO = 0:CV = 10
2950 GOSUB 39200:CF = CV
2970 GOSUB 21375: PRINT "ESTIMATED DRILLING DEPTH /M":
2980 HI = 1000:LO = 0:CV = 100
2990 GOSUB 39200:ED = CV
3000 GOSUB 5900
3010 GOSUB 21375: PRINT "CERTAINTY/DEPTH":
3020 HI = 100:LO = 0:CV = 10
3030 GOSUB 39200:C(1) = CV
3050 GOSUB 21375: PRINT "PREFERRED GEOTHERM.TEMP-C":
3060 HI = 500:LO = 0:CV = 60
3070 GOSUB 39200:GT = CV
3080 GOSUB 6020
3090 GOSUB 21375: PRINT "CERTAINTY/GEOTHERM TEMP":
3100 HI = 100:LO = 0:CV = 10
3110 GOSUB 39200:C(2) = CV
3130 GOSUB 21375: PRINT "TOTAL FLOW RATE- L.P.S.":
3140 HI = 8000:LO = 0:CV = 10
3150 GOSUB 39200:TF = CV * 60
3155 CV = TF
3160 GOSUB 6080
3170 GOSUB 21375: PRINT "CERTAINTY/FLOW RATE":
3180 HI = 100:LO = 0:CV = 10
3190 GOSUB 39200:C(4) = CV
3210 GOSUB 21375: PRINT "ENTER DRILLING DIFFICULTY":
3220 PRINT
3230 PRINT "1) UNCONSOLIDATED ROCKS"
3240 PRINT "2) YOUNG VOLCANICS"
3250 PRINT "3) OLDER VOLCANICS"
3260 PRINT "4) CRYSTALLINE ROCKS"
3270 HI = 4:LO = 1:CV = DF
3280 GOSUB 39200:DF = CV
3290 IF DF = 1 THEN Y = .275
3300 IF DF = 2 THEN Y = .15
3310 IF DF = 3 THEN Y = .15
3320 IF DF = 4 THEN Y = .1
3330 GOSUB 8060
3340 GOSUB 21375: PRINT "CERTAINTY/DRILL DIFFICULTY":
3350 HI = 100:LO = 0:CV = 10
3360 GOSUB 39200:C(5) = CV
3380 GOSUB 21375: PRINT "PROSPECT AREAL EXTENT /KM^2":
3390 HI = 200:LO = 0:CV = PA
3400 GOSUB 39200:PA = CV
3410 GOSUB 6150
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3420 GOSUB 21375: PRINT "CERTAINTY/AREA";
3430 HI = 100:LO = 0:CV = CT
3440 GOSUB 39200:C(6) = CV
3460 GOSUB 21375: PRINT "LOCAL GRADIENT-C/KM";
3470 HI = 500:LO = 0:CV = GG
3480 GOSUB 39200:GG = CV
3490 GOSUB 6180
3500 GOSUB 21375: PRINT "CERTAINTY/GRADIENT";
3510 HI = 100:LO = 0:CV = CT
3520 GOSUB 39200:C(7) = CV
3540 GOSUB 21375: PRINT "ESTIMATED PUMPING DEPTH";
3550 HI = 5000:LO = 0:CV = PD
3560 GOSUB 39200:PD = CV
3570 GOSUB 6210
3580 GOSUB 21375: PRINT "CERTAINTY/PUMPING DEPTH";
3590 HI = 100:LO = 0:CV = CT
3600 GOSUB 39200:C(8) = CV
3610 PRINT "***ENGINEERING MODULE**"
3620 GOSUB 21375: PRINT "DIST.TO HEATING LOAD-KM";
3630 HI = 300:LO = 0:CV = DL
3640 GOSUB 39200:DL = CV
3650 GOSUB 6270
3670 GOSUB 21375: PRINT "RESOURCE SITE ACCESIBILITY";
3680 PRINT
3690 PRINT "1) LIMITED ACCESS"
3700 PRINT "2) UNIMPROVED ROAD"
3710 PRINT "3) ALL WEATHER ROAD"
3720 HI = 3:LO = 0:CV = RA
3730 GOSUB 39200:RA = CV
3740 IF RA = 1 THEN Y = 0
3750 IF RA = 2 THEN Y = .5
3760 IF RA = 3 THEN Y = 1!
3770 GOSUB 8060
3790 GOSUB 21375: PRINT "TRENCHABILITY OF PIPELINE CORRIDOR";
3800 PRINT
3810 PRINT "1) HARD"
3820 PRINT "2) UNCONSOLIDATED/SOFT"
3830 HI = 2:LO = 1:CV = TP
3840 GOSUB 39200:TP = CV
3850 IF TP = 1 THEN Y = .3
3860 IF TP = 2 THEN Y = 1!
3870 GOSUB 8060
3890 GOSUB 21375: PRINT "PIPELINE TERRAIN CONCERNS";
3900 PRINT
3910 HI = 10:LO = 0:CV = TC
3920 GOSUB 39200:TC = CV
3930 IF TC = 0 THEN Y = 1!
3940 IF TC = 1 THEN Y = .66
3950 IF TC = 2 THEN Y = .33
3960 IF TC = 3 THEN Y = 0
3970 GOSUB 8060
4000 GOSUB 21375: PRINT "HEAT LOAD DENSITY";
4010 HI = 3:LO = 1:CV = DN
4020 PRINT
4030 PRINT "SELECT ONE OF THE FOLLOWING SUBROUTINES:": PRINT
4040 PRINT "1) URBAN"
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4050 PRINT "2) SUBURBAN"
4060 PRINT "3) RURAL"
4070 GOSUB 39200:DN = CV
4080 IF DN = 1 THEN GOSUB 4110
4090 IF DN = 2 THEN GOSUB 4160
4100 IF DN = 3 THEN GOSUB 4210
4110 GOSUB 21375: PRINT "ENTER URBAN HEATING LOAD-109 BTU/YR":
4120 HI = 5000:LO = 0:CV = UD
4130 GOSUB 39200:UD = CV
4140 GOSUB 5650
4150 GOTO 4270
4160 GOSUB 21375: PRINT "SUBURBAN HEATING LOAD-109 BTU/YR":
4170 HI = 5000:LO = 0:CV = SD
4180 GOSUB 39200:SD = CV
4190 GOSUB 5650
4200 GOTO 4270
4210 GOSUB 21375: PRINT "RURAL HEATING LOAD-109 BTU/YR":
4220 HI = 5000:LO = 0:CV = RD
4230 GOSUB 39200:RD = CV
4240 GOSUB 5710
4250 GOTO 4270
4270 GOSUB 21375: PRINT "LEAST COST HEAT ENERGY-1/106 BTU":
4280 HI = 100:LO = 0:CV = LE
4290 GOSUB 39200:LE = CV
4300 GOSUB 6430
4320 GOSUB 21375: PRINT "HEATING DEGREE DAYS":
4330 HI = 10000:LO = 4000:CV = DY
4340 GOSUB 39200:DD = DY
4350 GOSUB 6490
4370 PRINT "**REGULATORY/ENVIRONMENTAL MODULE**"
4380 PRINT "LAND/RESOURCE MANAGEMENT"
4390 PRINT "1) MIXED"
4400 PRINT "2) FED./STATE/LOCAL"
4410 PRINT "3) PRIVATE"
4420 HI = 3:LO = 0:CV = LR
4430 GOSUB 39200:LRM = CV
4440 IF LRM = 1 THEN Y = .4
4450 IF LRM = 2 THEN Y = .7
4460 IF LRM = 3 THEN Y = 1
4465 GOSUB 8060
4480 GOSUB 21375: PRINT "NO. OF ENVN./REG. CONCERNS":
4490 HI = 10:LO = 0:CV = EV
4500 GOSUB 39200:EV = CV
4510 IF EV = 0 THEN Y = 1
4520 IF EV = 1 THEN Y = .75
4530 IF EV = 2 THEN Y = .5
4540 IF EV = 3 THEN Y = .25
4550 IF EV = 4 THEN Y = 0
4560 GOSUB 8060
4580 GOSUB 21375: PRINT "DIST. LEGALLY DESIGNATED AREAS-1 M.":
4590 HI = 200:LO = 0:CV = DH
4600 GOSUB 39200:DH = CV
4610 GOSUB 5790
4630 GOSUB 21375: PRINT "NO. AIR/WATER CONCERNS":
4640 HI = 10:LO = 0:CV = AW
4650 GOSUB 39200:AW = CV
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4660 IF AW = 0 THEN Y = 1!
4670 IF AW = 1 THEN Y = .75
4680 IF AW = 2 THEN Y = .5
4690 IF AW = 3 THEN Y = .25
4700 IF AW = 4 THEN Y = 0!
4710 GOSUB 8060
4730 GOSUB 21375: PRINT "OWNER ATTITUDE TOWARD DEVELOPMENT":
4740 PRINT : PRINT "1) POSITIVE"
4750 PRINT "2) NEGATIVE"
4760 HI = 2:LO = 1:CV = OA
4770 GOSUB 39200:OA = CV
4780 IF OA = 1 THEN Y = 1!
4790 IF OA = 2 THEN Y = 0
4800 GOSUB 8060
4910 FOR Q = 1 TO 20
4920 S(Q) = F(Q) * V(Q)
4930 NEXT Q : REM home
4950 FOR M = 1 TO 20
4960 ST = S(M) + ST
4970 NEXT M
4990 GOSUB 8210: REM home
5010 PRINT "*** OUTPUT MENU-LO TEMP. ***"
5020 GOSUB 19000
5080 GOSUB 39200:RR = CV
5090 IF RR = 1 THEN GOSUB 8320
5100 IF RR = 2 THEN GOSUB 8350
5110 IF RR = 3 THEN GOSUB 5120
5120 GOTO 150
5290 B0 = 16.429:B1 = - .5793
5300 B2 = .0077644:B3 = - 5.0819E-05
5310 B4 = 1.7584E-07:B5 = - 3.0878E-10
5320 B6 = 2.1648E-13
5330 GOSUB 8000
5340 RETURN
5360 B0 = 1.0141:B1 = - 3.2751E-05
5370 B2 = 9.2026E-08:B3 = - 6.4246E-11
5380 B4 = - 7.7726E-15:B5 = 3.6899E-18
5390 B6 = 0
5400 GOSUB 8000
5410 RETURN
5460 A = 0:B = .04
5470 GOSUB 8130
5480 RETURN
5500 A = - 1.5:B = .024898
5510 GOSUB 8130
5520 RETURN
5570 A = 1:B = - .008
5580 GOSUB 8130: RETURN
5600 A = 1:B = - .03333
5610 GOSUB 8130
5620 RETURN
5650 A = 0:B = .0005
5660 GOSUB 8130: RETURN
5680 A = 0:B = .00025
5690 GOSUB 8130: RETURN
5710 A = 0:B = .000125
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5720 GOSUB 8130: RETURN
5750 A = 0: B = .01
5760 GOSUB 8130: RETURN
5790 B0 = .0131023: B1 = .933275
5800 B2 = - .713578: B3 = .354372
5810 B4 = - .0987493: B5 = .0141448
5820 B6 = - 8.0855E-04
5830 GOSUB 8000: RETURN
5860 A = 0: B = .008
5870 GOSUB 8130: RETURN
5900 B0 = .0045198: B1 = - .004767
5910 B2 = .0017749: B3 = - 1.0142E-04
5920 B4 = 2.464E-06: B5 = - 2.5931E-08
5930 B6 = 9.862E-11
5940 GOSUB 8000: RETURN
5960 B0 = .9542: B1 = 1.163
5970 B2 = - 5.801: B3 = 6.334
5980 B4 = - 3.087: B5 = .7113
5990 B6 = - .0632
6000 GOSUB 8000: RETURN
6020 B0 = .0045198: B1 = - .004767
6030 B2 = .0017749: B3 = - 1.0142E-04
6040 B4 = 2.464E-06: B5 = - 2.5931E-08
6050 B6 = 9.862E-11
6060 GOSUB 8000: RETURN
6080 B0 = - .005844: B1 = .0024135
6090 B2 = - 3.9388E-06: B3 = 3.4187E-09
6100 B4 = - 1.4254E-12: B5 = 2.2855E-16
6110 B6 = 0
6120 GOSUB 8000: RETURN
6150 A = 0: B = .125
6160 GOSUB 8130: RETURN
6180 A = - .3: B = .012
6190 GOSUB 8130: RETURN
6210 B0 = .98026: B1 = 4.40453E-03
6220 B2 = - 2.09911E-04: B3 = 3.06915E-06
6230 B4 = - 2.11179E-08: B5 = 6.85471E-11
6240 B6 = - 8.46177E-14
6250 GOSUB 8000: RETURN
6270 A = 1: B = - .00333
6280 GOSUB 8130: RETURN
6320 PRINT "(18) AIR WATER": U = 18: GOSUB 15475:
6340 A = 0: B = .0005
6350 GOSUB 8130: RETURN
6370 A = 0: B = .00025
6380 GOSUB 8130: RETURN
6400 A = 0: B = .000125
6410 GOSUB 8130: RETURN
6430 B0 = .0242: B1 = - .03069
6440 B2 = - .0023242: B3 = .008156
6450 B4 = - .003157: B5 = 5.9053E-05
6460 B6 = - 1.0407E-06
6470 GOSUB 8000: RETURN
6490 A = - 1: B = .00025
6500 GOSUB 8130: RETURN
6540 B0 = .0131023: B1 = .933275
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6550 B2 = - .710578;B3 = .35437  
6560 B4 = - .098749;B5 = .0141448  
6570 B6 = - .0008855  
6580 GOSUB 8000: RETURN  
6620 GOSUB 7140  
6630 GOTO 160  
6650 IF = 20  
6660 CT = .5  
6670 PD = 20  
6675 DY = 0  
6680 TP = 2  
6690 HD = 5000  
6700 UD = 2000  
6710 SD = 300  
6720 RD = 20  
6730 LE = 0  
6740 TE = 30  
6745 IN = 3  
6750 RA = 3  
6760 PA = 4  
6770 GG = 30  
6780 TC = 1  
6790 HL = 5  
6800 AL = 500  
6810 RS = 3  
6820 GT = 50  
6821 DF = 3  
6822 DH = 5  
6823 LR = 1  
6824 EV = 1  
6825 DL = 5  
6826 AW = 1  
6827 OA = 2  
6830 DD = 2  
6840 GOTO 7570  
6860 TE = 100  
6870 CT = .5  
6880 AG = 5  
6890 FE = 3  
6900 PA = 2  
6910 HF = 80  
6920 TC = 1  
6930 RS = 3  
6940 UD = 2000  
6950 SD = 300  
6960 RD = 20  
6970 HL = 5  
6980 AL = 500  
6990 LR = 1  
7000 PL = 0  
7010 DD = 2000  
7020 DF = 3  
7030 TD = 1  
7040 DN = 3  
7050 EV = 1  
7060 DL = 5

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7070 AW = 1
7080 OA = 1
7090 PW = 75
7110 GOTO 7190
7120 RETURN
7140 PRINT :T4=INKEY$: PRINT "PRESS ANY KEY TO CONTINUE . . .":
7141 IF INKEY$="" THEN 7141
7142 PRINT: RETURN
7190 V(1) = 14
7200 V(2) = 8
7220 V(3) = 12
7240 V(4) = 14
7260 V(5) = 4
7280 V(6) = 4
7300 V(7) = 4
7320 V(8) = 6
7340 V(9) = 4
7360 V(10) = 4
7380 V(11) = 10
7400 V(12) = 3
7420 V(13) = 3
7440 V(14) = 8
7460 V(15) = 6
7480 V(16) = 16
7500 V(17) = 5
7520 V(18) = 5
7530 GOTO 310
7570 V(1) = 11
7590 V(2) = 7
7610 V(3) = 4
7630 V(4) = 7
7650 V(5) = 2
7670 V(6) = 8
7690 V(7) = 6
7710 V(8) = 5
7730 V(9) = 8
7750 V(10) = 2
7770 V(11) = 2
7790 V(12) = 2
7810 V(13) = 22
7830 V(14) = 8
7850 V(15) = 6
7870 V(16) = 7
7890 V(17) = 12
7910 V(18) = 3
7930 V(19) = 5
7950 V(20) = 3
7960 GOTO 2840
8000 X = CV
8010 Y =B0+E1*X+E2*X^2+E3*X^3+E4*X^4+E5*X^5+E6*X^6
8060 IF Y = 1 THEN Y = 0
8062 IF Y = 0 THEN Y = 1
8064 ZZ = ZZ + 1: X = CV
8070 IF ZZ = 4 AND CH = 1 THEN X = CV / 60
8072 F(ZZ) = Y: X(ZZ) = X
8080 RETURN

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8150 X = CV:Y = F * X + A
8160 GOSUB 8060
8190 RETURN
8200 GOSUB 5050
8210 FOR H = 1 TO 8
8220 UC(H) = (S(H) * (1 - C(H))) / 2
8230 UZ = UZ + UC(H)
8240 NEXT H
8245 IF CH = 2 THEN UZ = UZ - (S(8) / 2)
8250 UX = UZ / .5
8260 SX = ST - UX
8270 RETURN
8319 REM Jprint part 29 OCT 84
8320 PRINT "printer on...":PR=1
8340 PRINT : IF PR THEN LPRINT
8350 GOSUB 17050
8360 T4="LOW TEMPERATURE RESOURCE RANKING DATA":PRINT TAB(Z1) T4
8361 IF PR THEN LPRINT TAB(Z1) T4
8365 PRINT TAB(Z1) STRING$(37,"-")
8366 IF PR THEN LPRINT TAB(Z1) STRING$(37,"-")
8370 GOSUB 17000
8410 T4=" CHARACTERISTICS POINTS UC/2":PRINT TAB(Z1) T4
8411 IF PR THEN LPRINT TAB(Z1) T4
8415 PRINT TAB(Z1) STRING$(39,"=")
8416 IF PR THEN LPRINT TAB(Z1) STRING$(39,"=")
8420 PRINT
8421 IF PR THEN LPRINT
8430 PRINT TAB(Z1) "RESOURCE"
8431 IF PR THEN LPRINT TAB(Z1) "RESOURCE"
8435 PRINT TAB(Z1) "-----"
8436 IF PR THEN LPRINT TAB(Z1) "-----"
8440 PRINT: IF PR THEN LPRINT
8450 T4="1) FLUIDS-TEMP.":PRINT T4:IF PR THEN LPRINT T4:
8455 U=1:GOSUB 8845
8460 T4="2) DRILLING DEPTH":PRINT T4:IF PR THEN LPRINT T4:
8465 U=2:GOSUB 8845
8470 T4="3) GEOTHERM. TEMP.":PRINT T4:IF PR THEN LPRINT T4:
8475 U=3:GOSUB 8845
8480 T4="4) FLOWRATE":PRINT T4:IF PR THEN LPRINT T4:
8485 U=4:GOSUB 8845
8490 T4="5) DRILLING DIFF.":PRINT T4:IF PR THEN LPRINT T4:
8495 U=5:GOSUB 8845
8500 T4="6) AREA EXTENT":PRINT T4:IF PR THEN LPRINT T4:
8501 U=6:GOSUB 8845
8510 T4="7) LOCAL GRADIENT":PRINT T4:IF PR THEN LPRINT T4:
8511 U=7:GOSUB 8845
8520 T4="8) PUMPING DEPTH":PRINT T4:IF PR THEN LPRINT T4:
8521 U=8:GOSUB 8845
8525 GOSUB 17000
8530 PRINT : IF PR = 1 THEN GOSUB 7140: PRINT : PRINT
8531 IF PR THEN LPRINT
8540 PRINT TAB(Z1)"ENGINEERING":IF PR THEN LPRINT TAB(Z1) "ENGINEERING"
8545 PRINT TAB(Z1) "-----":IF PR THEN LPRINT TAB(Z1) "-----"
8550 PRINT:IF PR THEN LPRINT
8560 T4="9) HEAT-LOAD-DIST.":PRINT T4:IF PR THEN LPRINT T4:
8561 U=9:GOSUB 8850
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8570 T4="10) SITE ACCESS":PRINT T4::IF PR THEN LPRINT T4:
8571 U=10:GOSUB 8850
8580 T4="11) TRENCHABILITY":PRINT T4::IF PR THEN LPRINT T4:
8581 U=11:GOSUB 8850
8590 T4="12) TOPRAIN":PRINT T4::IF PR THEN LPRINT T4:
8591 U=12:GOSUB 8850
8600 T4="13) ANN.LOAD DENSITY":PRINT T4::IF PR THEN LPRINT T4:
8601 U=13:GOSUB 8850
8610 T4="14) LEAST ENERGY":PRINT T4::IF PR THEN LPRINT T4:
8611 U=14:GOSUB 8850
8620 T4="15) HEATING D.DAYS":PRINT T4::IF PR THEN LPRINT T4:
8621 U=15:GOSUB 8850
8625 GOSUB 17000
8630 PRINT:IF PR THEN LPRINT
8640 PRINT TAB(Z1)"REGULATORY/ENVIRON."
8641 IF PR THEN LPRINT TAB(Z1)"REGULATORY/ENVIRON."
8645 PRINT TAB(Z1)"-----"
8646 IF PR THEN LPRINT TAB(Z1)"-----"
8650 PRINT
8655 IF PR THEN LPRINT
8660 T4="16) LAND/RESOURCE-MON.":PRINT T4::IF PR THEN LPRINT T4:
8661 U=16:GOSUB 8850
8670 T4="17) SPECIAL REG. ENV.":PRINT T4::IF PR THEN LPRINT T4:
8671 U=17:GOSUB 8850
8680 T4="18) DIST.LEG.ARCAS":PRINT T4::IF PR THEN LPRINT T4:
8681 U=18:GOSUB 8850
8690 T4="19) APL/WATER":PRINT T4::IF PR THEN LPRINT T4:
8691 U=19:GOSUB 8850
8700 T4="20) OWNER ALTITUDE":PRINT T4::IF PR THEN LPRINT T4:
8701 U=20:GOSUB 8850
8705 GOSUB 17000
8710 PRINT : IF PR = 2 THEN GOSUB 17000:PRINT : PRINT
8711 IF PR THEN LPRINT
8715 PRINT TAB(Z1):
8716 IF PR THEN LPRINT TAB(Z1):
8720 SZ=SZ:WD=7:GOSUB 19520:PRINT "TOTAL"TAB(Z2) SZ TAB(Z3):
8721 IF PR THEN LPRINT "TOTAL"TAB(Z2) SZ TAB(Z3):
8722 SZ=UZ:WD=7:GOSUB 19520:PRINT SZ#
8723 IF PR THEN LPRINT SZ#
8725 PRINT TAB(Z1) STRING$(OP,"="):IF PR THEN LPRINT TAB(Z1)STRING$(OP,"=")
8730 PRINT:IF PR THEN LPRINT
8740 GOSUB 9000
8810 PRINT "PRINTER OFF...":PF=0
8815 GOSUB 9040
8817 GOTO home
8818 PRINT "FIND RESOURCE INPUT DATA":PRINT : PRINT
8819 GOSUB 15000
8820 GOSUB 39000:PF=CV
8821 IF PR = 1 THEN GOSUB 15000
8822 IF PR = 2 THEN GOSUB 15000
8823 IF PR = 3 THEN GOTO 15000
8830 RETURN
8840 GOSUB 19500:PRINT SZ#:GOSUB 18000:IF PR THEN LPRINT SZ#:
8841 RETURN
8845 GOSUB 8800:GOSUB 19500:PRINT C1#:IF PR THEN LPRINT SZ#
8846 RETURN

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8850 GOSUB 19500: PRINT SZ#:GOSUB 18000:IF PR THEN LPRINT SZ#
8851 RETURN
8880 PRINT "PRINTER ON...":PR=1
8900 GOSUB 17050
8910 PRINT: IF PR THEN LPRINT
8920 T#="HIGH TEMPERATURE RESOURCE RANKING DATA":PRINT T#
8921 IF PR THEN LPRINT T#
8925 PRINT STRING$(38,"-"):IF PR THEN LPRINT STRING$(38,"-")
8930 GOSUB 17500
8970 T#=" CHARACTERISTICS POINTS UC#2":PRINT TAB(Z1)T#
8971 IF PR THEN LPRINT TAB(Z1)T#
8975 PRINT TAB(Z1) STRING$(39,"="):IF PR THEN LPRINT TAB(Z1) STRING$(39,"=")
8980 PRINT: IF PR THEN LPRINT
8990 PRINT TAB(Z1)"RESOURCE":IF PR THEN LPRINT TAB(Z1)"RESOURCE"
8995 PRINT TAB(Z1)"-----":IF PR THEN LPRINT TAB(Z1)"-----"
9000 PRINT: IF PR THEN LPRINT
9010 T#="1) EST.RESERVOR.TEMP":PRINT T#::IF PR THEN LPRINT T#:
9011 U=1:GOSUB 9400
9020 T#="2) DRILLING DEPTH":PRINT T#::IF PR THEN LPRINT T#:
9021 U=2:GOSUB 9400
9030 T#="3) AGE-TYPE-VOLC.":PRINT T#:: IF PR THEN LPRINT T#:
9031 U=3:GOSUB 9400
9040 T#="4) POT.H1.PERM.":PRINT T#::IF PR THEN LPRINT T#:
9041 U=4:GOSUB 9400
9050 T#="5) DRILLING DIFF.":PRINT T#::IF PR THEN LPRINT T#:
9051 U=5:GOSUB 9400
9060 T#="6) AREA EXTENT":PRINT T#::IF PR THEN LPRINT T#:
9061 U=6:GOSUB 9400
9070 T#="7) HEAT FLOW":PRINT T#::IF PR THEN LPRINT T#:
9071 U=7:GOSUB 9400
9075 GOSUB 17000
9080 PRINT : IF PR = 2 THEN GOSUB 7140: PRINT : PRINT
9090 PRINT TAB(Z1)"ENGINEERING":IF PR THEN LPRINT TAB(Z1) "ENGINEERING"
9095 PRINT TAB(Z1)"-----":IF PR THEN LPRINT TAB(Z1) "-----"
9100 PRINT: IF PR THEN LPRINT
9110 T#="8) TERRAIN PWRLN":PRINT T#::IF PR THEN LPRINT T#:
9111 U=8:GOSUB 9410
9120 T#="9) SITE ACCESS":PRINT T#::IF PR THEN LPRINT T#:
9121 U=9:GOSUB 9410
9130 T#="10) SITE TERRAIN":PRINT T#::IF PR THEN LPRINT T#:
9131 U=10:GOSUB 9410
9140 T#="11) DIST.TO.PWBLN":PRINT T#::IF PR THEN LPRINT T#:
9141 U=11:GOSUB 9410
9150 T#="12) DIST.HEAT.LOAD":PRINT T#::IF PR THEN LPRINT T#:
9151 U=12:GOSUB 9410
9160 T#="13) ANN.LOAD.DENSITY":PRINT T#::IF PR THEN LPRINT T#:
9161 U=13:GOSUB 9410
9170 GOSUB 17000
9180 T#="REGULATORY/ENVIRON.":PRINT TAB(Z1) T#
9181 IF PR THEN LPRINT TAB(Z1) T#
9185 PRINT TAB(Z1)"-----"
9186 IF PR THEN LPRINT TAB(Z1) "-----"
9190 PRINT:PRINT:IF PR THEN LPRINT:LPRINT
9200 T#="14) LAND/RESOURCE-MGN.":PRINT T#::IF PR THEN LPRINT T#:
9201 U=14:GOSUB 9420
9210 T#="15) %LEASED EXPLOR.":PRINT T#::IF PR THEN LPRINT T#:

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9211 U=15:GOSUB 9420
9220 T4="16) SPEC. REQ. ENV.":PRINT T4::IF PR THEN LPRINT T4:
9221 U=16:GOSUB 9420
9230 T4="17) DIST. LOC. AREAS":PRINT T4::IF PR THEN LPRINT T4:
9231 U=17:GOSUB 9420
9240 T4="18) AIR WATER":PRINT T4::IF PR THEN LPRINT T4:
9241 U=18:GOSUB 9420
9245 GOSUB 17000
9250 PRINT : IF RR = 3 THEN GOSUB 7140: PRINT : PRINT
9260 SZ = ST:WD = 7: GOSUB 19520: PRINT TAB(Z1)"TOTAL"TAB(Z2)SZ#:
9261 IF PR THEN LPRINT TAB(Z1)"TOTAL"TAB(Z2)SZ#:
9262 SZ=UZ:WD=7:GOSUB 19520: PRINT TAB(Z7)SZ#:IF PR THEN LPRINT TAB(Z7)SZ#:
9265 PRINT TAB(Z1) STRING$(39,"="):IF PR THEN LPRINT TAB(Z1) STRING$(39,"=")
9270 PRINT: IF PR THEN LPRINT
9280 GOSUB 9500
9350 PR=0: PRINT "PRINTER OFF..."
9355 GOSUB 7140
9357 REM home
9359 PRINT "PRINT RESOURCE INPUT DATA": PRINT : PRINT
9361 GOSUB 19000
9363 GOSUB 39200:RR = CV
9365 IF RR = 1 THEN GOSUB 16000
9366 IF RR = 2 THEN GOSUB 16010
9367 IF RR = 3 THEN GOTO 150
9370 RETURN
9400 GOSUB 19500:PRINT SZ#:IF PR THEN LPRINT SZ#:
9401 GOSUB 18000:GOSUB 19510:PRINT SZ#:IF PR THEN LPRINT SZ#:
9402 RETURN
9410 GOSUB 19500:PRINT SZ#:IF PR THEN LPRINT SZ#:
9411 GOSUB 18000: RETURN
9420 GOSUB 19500:PRINT SZ#:IF PR THEN LPRINT SZ#:
9421 GOSUB 18000:RETURN
9425 GOSUB 19475:PRINT SZ#:IF PR THEN LPRINT SZ#:
9426 RETURN
9430 GOSUB 19485:PRINT SZ#:IF PR THEN LPRINT SZ#:
9431 RETURN
9560 SZ4 = SZ# + "00":S7# = LEFT$(SZ4,OR + 2):SZ4 = RIGHT$(SZ4,4) + SZ#,WD
): PRINT SZ4:: RETURN
9600 PRINT TAB(74)"SORT UC 2= "FN R(U)
9601 IF PR THEN LPRINT TAB(74)"SORT UC 2= "FN R(U)
9610 PRINT:PRINT:PRINT:IF PR THEN LPRINT:LPRINT:LPRINT
9620 SZ=ST:WD=7:GOSUB 19520:T4="MOST LIKELY SCORE":PRINT T4 TAB(Z7)SZ4
9621 IF PR THEN LPRINT T4 TAB(Z7)SZ4
9670 SZ=UZ:WD=7:GOSUB 19520:T4="PROBABLE UNCERTAINTY":PRINT T4TAB(Z7)SZ4
9621 IF PR THEN LPRINT T4 TAB(Z7)SZ4
9640 SZ=SX:WD=7:GOSUB 19520:T4="LIKELY MONTHLY SCORE":PRINT T4 TAB(Z7)SZ4
9641 IF PR THEN LPRINT T4 TAB(Z7)SZ4
9645 PRINT: IF PR THEN LPRINT
9650 SZ=SY:WD=7:T4="NORMALIZED MONTHLY SCORE":PRINT T4 TAB(Z7)SZ4
9651 IF PR THEN LPRINT T4 TAB(Z7)SZ4
9652 PRINT:PRINT:PRINT:IF PR THEN LPRINT:LPRINT:LPRINT
9655 RETURN
15000 GOSUB 18100 :PRINT "PRINTER ON...":PR=1
15010 PRINT : GOSUB 17050:PRINT TAB(Z1)::IF PR THEN LPRINT:LPRINT TAB(Z1):
15020 T4="LOW TEMP. RESOURCE INPUT DATA":PRINT T4:IF PR THEN LPRINT T4:
15025 PRINT TAB(Z1) STRING$(29,"="):IF PR THEN LPRINT TAB(Z1) STRING$(29,"=")
15030 GOSUB 17500
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15040 T#=" CHARACTERISTICS":PRINT TAB(Z1) T# TAB(Z6)"EST."TAB(Z6)"CERTAINTY"
15041 IF PR THEN LPRINT TAB(Z1) T# TAB(Z6)"EST."TAB(Z6)"CERTAINTY"
15045 PRINT TAB(Z1) STRING$(40,"="):IF PR THEN LPRINT TAB(Z1) STRING$(40,"=")
15050 PRINT : PRINT TAB(Z1)::IF PR THEN LPRINT:LPRINT TAB(Z1):
15060 PRINT "RESOURCE":IF PR THEN LPRINT "RESOURCE"
15065 PRINT TAB(Z1) "-----":IF PR THEN LPRINT TAB(Z1) "-----"
15070 PRINT : IF PR THEN LPRINT
15080 T#="1) FLUIDS-TEMP.":PRINT T#::IF PR THEN LPRINT T#:
15081 U=1:GOSUB 9425:PRINT " C":IF PR THEN LPRINT " C":
15082 GOSUB 9430
15090 T#="2) DRILL.DEPTH":PRINT T#::IF PR THEN LPRINT T#:
15091 U=2:GOSUB 9425:PRINT " KM":IF PR THEN LPRINT " KM":
15092 GOSUB 9430
15100 T#="3) GEOTHERM.TEMP.":PRINT T#::IF PR THEN LPRINT T#:
15101 U=3:GOSUB 9425:PRINT " C":IF PR THEN LPRINT " C":
15102 GOSUB 9430
15110 T#="4) FLOWRATE":PRINT T#::IF PR THEN LPRINT T#:
15111 U=4:GOSUB 9425:PRINT " L/S":IF PR THEN LPRINT " L/S":
15112 GOSUB 9430
15120 T#="5) DRILLING DIFF.":PRINT T#::IF PR THEN LPRINT T#:
15121 U=5:GOSUB 9425:GOSUB 9430
15130 T#="6) AREA EXTENT":PRINT T#::IF PR THEN LPRINT T#:
15131 U=6:GOSUB 9425:PRINT " KM^2":IF PR THEN LPRINT " KM^2":
15132 GOSUB 9430
15140 T#="7) LOCAL GRAD.":PRINT T#::IF PR THEN LPRINT T#:
15141 U=7:GOSUB 9425:PRINT " C/KM":IF PR THEN LPRINT " C/KM":
15142 GOSUB 9430
15150 T#="8) PUMP.DEPTH":PRINT T#::IF PR THEN LPRINT T#:
15151 U=8:GOSUB 9425:PRINT " M":IF PR THEN LPRINT " M":
15152 GOSUB 9430
15160 IF PR = 2 THEN GOSUB 7140:PRINT :PRINT
15165 PRINT :PRINT TAB(Z1)::IF PR THEN LPRINT:LPRINT TAB(Z1):
15170 PRINT "ENGINEERING":IF PR THEN LPRINT "ENGINEERING"
15175 PRINT TAB(Z1) "-----":IF PR THEN LPRINT TAB(Z1) "-----"
15180 PRINT:IF PR THEN LPRINT
15190 T#="9) LOAD DIST.":PRINT T#::IF PR THEN LPRINT T#:
15191 U=9:GOSUB 9425:PRINT " KM":IF PR THEN LPRINT " KM"
15200 T#="10) SITE ACCESS":PRINT T#::IF PR THEN LPRINT T#:
15201 U=10:GOSUB 9425:PRINT:IF PR THEN LPRINT
15210 T#="11) TRENCHABILTY":PRINT T#::IF PR THEN LPRINT T#:
15211 U=11:GOSUB 9425:PRINT:IF PR THEN LPRINT
15220 T#="12) TERRAIN":PRINT T#::IF PR THEN LPRINT T#:
15221 U=12:GOSUB 9425:PRINT:IF PR THEN LPRINT
15230 T#="13) AN.LD.DENSLTY":PRINT T#::IF PR THEN LPRINT T#:
15231 U=13:GOSUB 9425:PRINT " 10^9 BTU/YR":IF PR THEN LPRINT " 10^9 BTU/YR"
15240 T#="14) LEAST ENERGY":PRINT T#::IF PR THEN LPRINT T#:
15241 U=14:GOSUB 9425:PRINT " 4/10^6 BTU":IF PR THEN LPRINT " 4/10^6 BTU"
15250 T#="15) H.D.D.":PRINT T#::IF PR THEN LPRINT T#:
15251 U=15:GOSUB 9425:PRINT " 65 F.BASE":IF PR THEN LPRINT " 65 F.BASE"
15270 PRINT:PRINT "REGULATORY ENVIRON.":PRINT STRING$(19,"-"):PRINT
15280 IF PR THEN LPRINT:LPRINT "REGULATORY ENVIRON."
15290 IF PR THEN LPRINT STRING$(19,"-"):LPRINT
15300 T#="16) LAND/RSRC-NGN.":PRINT T#::IF PR THEN LPRINT T#:
15301 U=16:GOSUB 19475:PRINT SZ#:IF PR THEN LPRINT SZ#
15310 T#="17) SPEC.REG./ENV.":PRINT T#::IF PR THEN LPRINT T#:
15311 U=17:GOSUB 19475:PRINT SZ#:IF PR THEN LPRINT SZ#
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15320 T#="18) DIST.LEG.AREAS":PRINT T#::IF PR THEN LPRINT T#:
15321 U=18:GOSUB 19475:PRINT SZ# " FM":IF PR THEN LPRINT SZ# " FM"
15330 T#="19) AIR/WATER":PRINT T#::IF PR THEN LPRINT T#:
15331 U=19:GOSUB 19475:PRINT SZ#:IF PR THEN LPRINT SZ#
15340 T#="20) OWNER ATTITUDE":PRINT T#::IF PR THEN LPRINT T#:
15341 U=20:GOSUB 19475:PRINT SZ#:IF PR THEN LPRINT SZ#
15350 IF RR = 2 THEN GOSUB 7140: PRINT : PRINT
15355 PRINT:PRINT:PRINT TAB(Z1) STRING$(39,"=")
15356 IF PR THEN LPRINT:LPRINT:LPRINT:PRINT TAB(Z1) STRING$(39,"=")
15360 PRINT "PRINTER OFF...": PR=0: RETURN
16000 PR=1: PRINT "PRINTER ON...": GOSUB 18100
16010 PRINT : GOSUB 17050:IF PR THEN LPRINT
16020 T#="HIGH TEMP.RESOURCE INPUT DATA":PRINT TAB(Z1) T#
16021 IF PR THEN LPRINT TAB(Z1) T#
16025 PRINT TAB(Z1) STRING$(28,"-"):IF PR THEN LPRINT TAB(Z1) STRING$(28,"-")
16030 GOSUB 17500
16040 T#=" CHARACTERISTICS EST. CERTAINTY":PRINT TAB(Z1)T#
16041 IF PR THEN LPRINT TAB(Z1) T#
16045 PRINT TAB(Z1) STRING$(34,"="):IF PR THEN LPRINT TAB(Z1) STRING$(34,"=")
16048 PRINT: IF PR THEN LPRINT
16050 PRINT TAB(Z1) "RESOURCE":IF PR THEN LPRINT TAB(Z1) "RESOURCE"
16060 PRINT TAB(Z1) "-----":IF PR THEN LPRINT TAB(Z1) "-----"
16070 PRINT: IF PR THEN LPRINT
16080 T#="1) EST.RSRV.TEMP":PRINT T#::IF PR THEN LPRINT T#:
16081 U=1:GOSUB 19475:PRINT SZ# " C":IF PR THEN LPRINT SZ# " C":
16082 GOSUB 19485:PRINT SZ#:IF PR THEN LPRINT SZ#
16090 T#="2) DRILL.DEPTH":PRINT T#::IF PR THEN LPRINT T#:
16091 U=2:GOSUB 19475:PRINT SZ# " M":IF PR THEN LPRINT SZ# " M":
16092 GOSUB 19485:PRINT SZ#:IF PR THEN LPRINT SZ#
16100 T#="3) AGE-TYPE-VOLC.":PRINT T#::IF PR THEN LPRINT T#:
16101 U=3:GOSUB 19475:PRINT SZ#::IF PR THEN LPRINT SZ#:
16102 GOSUB 19485:PRINT SZ#:IF PR THEN LPRINT SZ#
16110 T#="4) POT.HI.PERM.":PRINT T#::IF PR THEN LPRINT T#:
16111 U=4:GOSUB 19475:PRINT SZ#::IF PR THEN LPRINT SZ#:
16112 GOSUB 19485:PRINT SZ#:IF PR THEN LPRINT SZ#
16120 T#="5) DRILLING DIFF.":PRINT T#::IF PR THEN LPRINT T#:
16121 U=5:GOSUB 19475:PRINT SZ#::IF PR THEN LPRINT SZ#:
16122 GOSUB 19485:PRINT SZ#:IF PR THEN LPRINT SZ#
16130 T#="6) AREA EXTENT":PRINT T#::IF PR THEN LPRINT T#:
16131 U=6:GOSUB 19475:PRINT SZ# " KM 2":IF PR THEN LPRINT SZ# " KM 2":
16132 GOSUB 19485:PRINT SZ#:IF PR THEN LPRINT SZ#
16140 T#="7) HEAT FLOW":PRINT T#::IF PR THEN LPRINT T#:
16141 U=7:GOSUB 19475:PRINT SZ# " MW/M 2":IF PR THEN LPRINT SZ# " MW/M 2":
16142 GOSUB 19485:PRINT SZ#: IF PR THEN LPRINT SZ#
16160 IF PR = 2 THEN GOSUB 7140: PRINT
16165 PRINT: IF PR THEN LPRINT
16170 PRINT TAB(Z1) "ENGINEERING": IF PR THEN LPRINT TAB(Z1) "ENGINEERING"
16175 PRINT TAB(Z1) "-----":IF PR THEN LPRINT TAB(Z1) "-----"
16180 PRINT: IF PR THEN LPRINT
16190 T#="8) TERRAIN PWRLN":PRINT T#::IF PR THEN LPRINT T#:
16191 U=8:GOSUB 19475:PRINT SZ#:IF PR THEN LPRINT SZ#
16200 T#="9) SITE ACCESS":PRINT T#::IF PR THEN LPRINT T#:
16201 U=9:GOSUB 19475:PRINT SZ#:IF PR THEN LPRINT SZ#
16210 T#="10) SITE TERRAIN":PRINT T#::IF PR THEN LPRINT T#:
16211 U=10:GOSUB 19475:PRINT SZ#:IF PR THEN LPRINT SZ#
16220 T#="11) PWRLN.DIST.":PRINT T#::IF PR THEN LPRINT T#:

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16221 U=11:GOSUB 19475:PRINT SZ$ " KM":IF PR THEN LPRINT SZ$ " KM"
16230 T$="12) LOAD DIST.":PRINT T$::IF PR THEN LPRINT T$:
16231 U=12:GOSUB 19475:PRINT SZ$ " KM":IF PR THEN LPRINT SZ$ " KM"
16240 T$="13) AN.LD.DENSITY":PRINT T$::IF PR THEN LPRINT T$:
16241 U=13:GOSUB 19475:T$=" 10^9 BTU/YR":PRINT SZ$ T$:IF PR THEN LPRINT SZ$
16245 PRINT: IF PR THEN LPRINT
16260 PRINT TAB(Z1)"REGULATORY/ENVIRON." TAB(Z1) STRING$(19,"-")
16261 IF PR THEN LPRINT TAB(Z1) "REGULATORY/ENVIRON." TAB(Z1) STRING$(19,"-")
16270 PRINT : PRINT: IF PR THEN LPRINT:LPRINT
16280 T$="14) LAND/RESCR.MGN.":PRINT T$::IF PR THEN LPRINT T$:
16281 U=14:GOSUB 19475:PRINT SZ$:IF PR THEN LPRINT SZ$
16290 T$="15) %LEASED EXPLOR.":PRINT T$::IF PR THEN LPRINT T$:
16291 U=15:GOSUB 19475:PRINT SZ$ "%":IF PR THEN LPRINT SZ$ "%"
16300 T$="16) SPEC.REG./ENV.":PRINT T$::IF PR THEN LPRINT T$:
16301 U=16:GOSUB 19475:PRINT SZ$:IF PR THEN LPRINT SZ$
16310 T$="17) DIST.LEG.AREAS":PRINT T$::IF PR THEN LPRINT T$:
16311 U=17:GOSUB 19475:PRINT SZ$ " KM":IF PR THEN LPRINT SZ$ " KM"
16320 T$="18) AIR/WATER":PRINT T$::IF PR THEN LPRINT T$:
16321 U=18:GOSUB 19475:PRINT SZ$:IF PR THEN LPRINT SZ$
16330 IF RR = 2 THEN GOSUB 7140: PRINT : PRINT
16335 PRINT : PRINT : PRINT TAB(Z1) STRING$(39,"=")
16336 IF PR THEN LPRINT:LPRINT:LPRINT TAB(Z1)STRING$(39,"=")
16340 PR=0: PRINT "PRINTER OFF...": RETURN
17000 PRINT:PRINT TAB(Z1) "SUBTOTAL":GOSUB 18500
17020 IF PR THEN LPRINT:LPRINT TAB(Z1) "SUBTOTAL":
17030 GOSUB 19450: PRINT SZ$:C=0: PRINT:IF PR THEN LPRINT SZ$:LPRINT
17050 IF RR = 1 THEN Z1 = 7: GOSUB 17100
17060 IF RR = 2 THEN Z1 = 1: GOSUB 17100
17070 RETURN
17100 Z2 = Z1 + 23:Z3 = Z1 + 33
17110 Z4 = Z1 + 14:Z5 = Z1 + 35:Z6 = Z1 + 21:Z0 = Z1 + 31
17120 Z7 = Z1 + 32:Z8 = Z1 + 19:Z9 = Z1 + 2
17140 RETURN
17500 PRINT: IF PR THEN LPRINT
17505 IF NM$ = "" THEN GOTO 17540
17507 PRINT TAB(Z1)::IF PR THEN LPRINT TAB(Z1):
17510 PRINT "SITE: " NM$:IF PR THEN LPRINT "SITE: " NM$
17515 IF CM$ = "" THEN GOTO 17540
17520 PRINT TAB(Z1)CM$ COUNTY. "SM$:IF PR THEN LPRINT TAB(Z1)CM$ COUNTY. "
17540 PRINT:IF PR THEN LPRINT
17550 RETURN
18000 C = C + 1
18010 TZ(C) = VAL (SZ$)
18020 RETURN
18100 FOR FF = 1 TO 10
18110 PRINT : NEXT : RETURN
18500 TP = 0
18507 FOR VV = 1 TO C
18510 TP = TP + TZ(VV)
18520 NEXT : RETURN
19000 PRINT "→→OUTPUT SELECTION →→"
19010 PRINT
19020 PRINT "1) HARD COPY"
19030 PRINT "2) MONITOR DISPLAY"
19040 PRINT "3) RETURN TO PROGRAM MENU"
19050 HI = 3:LO = 1:CV = 2

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```

19060 RETURN
19450 PRINT TAB(Z2)::SZ=IF:WD=7: GOSUB 19520:IF PR THEN LPRINT TAB(Z2):
19451 RETURN
19475 SZ=X(U):WD=7:GOSUB 19520:PRINT TAB(Z8)::IF PR THEN LPRINT TAB(Z8):
19476 RETURN
19485 SZ=C(U):WD=6:GOSUB 19520: PRINT TAB(Z3)::IF PR THEN LPRINT TAB(Z3):
19486 RETURN
19500 PRINT TAB(Z2)::SZ = S(U):WD = 7: GOSUB 19520:IF PR THEN LPRINT TAB(Z2):
19501 RETURN
19510 PRINT TAB(Z3)::SZ = UC(U):WD = 6: GOSUB 19520:IF PR THEN LPRINT TAB(Z3):
19511 RETURN
19520 SZ=SZ+.005:IF SZ <= .005 THEN SZ=0
19525 IF SZ>999 THEN SZ=SZ-.005
19540 SZ4=STR$(SZ) : IF SZ < 1 THEN SZ4 = "0"RIGHT$(SZ4,LEN(SZ4)-1)
19550 L=LEN(SZ4):FOR CR= L TO 1 STEP-1
19552 IF MID$(SZ4,CR,1) < "." THEN NEXT:SZ4=SZ4+"." :CR=CR+1
19560 SZ4=SZ4+"00":SZ4=LEFT$(SZ4,CR+2):SZ4=RIGHT$(SZ4,WD) : RETURN
19600 Z2 = 0:S1 = 0:UZ = 0:UX = 0:SX = 0
19610 FOR OO = 1 TO 20
19620 P(OO)=0:U(OO)=0:V(OO)=0:S(OO)=0:UC(OO)=0:C(OO)=0:IZ(OO)=0:X(OO)=0
19630 NEXT : RETURN
19700 PRINT : PRINT
19720 PRINT "ENTER RESOURCE NAME AS FOLLOWS:"
19730 PRINT
19740 PRINT : INPUT "NAME OF SITE:":NM$
19750 PRINT : INPUT "COUNTY:":CM$
19760 PRINT : INPUT "STATE:":SM$
19770 RETURN
20170 PRINT : PRINT "YOUR SELECTION = " :
20180 GOSUB 20370:A = VAL (A$): IF A < LO OR A > HI THEN 20170
20190 RETURN
20370 REM new string input routine
20390 AE$=CHR$(13)
20400 LINE INPUT A$
20410 L=LEN(A$)
20420 A$=A$:REM I'm not sure why this is here...
20520 RETURN
21075 REM vtab htab stuff -- hope it won't be missed
21380 RETURN
21480 PRINT "error routine -- should not occur. Call for help..."
21555 RETURN
22030 REM * SCREEN SETUPS *
22040 RETURN:REMPOKE 34,TM:POKE 35,BM:POKE 36,LM:POKE 37,WR: RETURN
22100 RETURN:REMPOKE 34,TM: RETURN : REM TOP
22110 RETURN:REMPOKE 35,BM: RETURN : REM BOTTOM
22120 RETURN:REMPOKE 36,LM:POKE 37,WR = LM: RETURN : REM LEFT AND WIDTH
22130 RETURN:REMPOKE 35,BM: RETURN : REM WINDOW HEIGHT
22180 RETURN:REMPOKE 36,HC: RETURN : REM HORIZONTAL CURSOR
23000 REM def string and check range
23010 GOSUB 20370
23020 IF A$="" THEN RETURN
23130 IF VAL (A$) < LO AND VAL (A$) > HI THEN CLS:A$=A$:RETURN
23115 PRINT "MUST BE FROM "LO" TO "HI: PRINT: GOTO 23130
23150 RETURN REM end of range check
23200 PRINT "CURRENT VALUE = " :C$
23750 GOSUB 20370: RETURN

```

BRASC1 05/05/85  
20

---

50000 PRINT : PRINT "THAT'S ALL FOLKS!"





## APPENDIX 9

### Direct Utilization Ranking - GEORANK Program

- o GEORANK Summary
- o GEORANK Computer Program Listing (See Appendix 8)



## THE GEORANK PROGRAM

The GEORANK computer program was designed to evaluate the development potential for high temperature and direct use geothermal sites in the Pacific Northwest. Specifically, the objective was to identify resources which warrant more detailed investigation. This can save considerable time in the engineering -- economic analyses that will be required for ultimate resource definition. In this fashion, the GEORANK program is a screening tool for geothermal resources.

The program development was centered around a central question. What is the least information that we need to estimate the development potential of a geothermal resource? The characteristics examined represent all the major issues that the assessment team could identify that have major impact on geothermal project potential using commonly available data.

The technique is exploration oriented and is widely applicable to a variety of site types. Thus, the questions that are asked in the course of the program inputs simulate the issues that a geothermal exploration company would likely consider in assessment of a portfolio of resources. We believe that this structure makes the method more useful for a first time survey of geothermal sites in a regional area.

Each variable that is estimated to be important in development potential is assigned a numerical weight in the program which is correlated against a regression variable to determine the fractional development potential for that characteristic. The correlations are usually of a linear or polynomial types. The resulting scores of each variable is then summed for the overall development potential.

GEORANK takes into account both geologic and economic realities inherent in geothermal development. Implicit assumptions are made on the effect of geological data and its implications for project cost. An important facet of the method is that the uncertainties that surround important aspects in the resource determination are identified and approximated. More subjective aspects of system engineering and environmental and institutional aspects are also evaluated. This lends this method of evaluation an important advantage over conventional engineering analysis which typically ignores the importance of such "subjective considerations."

The system is used to rank overall site developability in a relative fashion. Thus, the program results have no meaning apart from a comparative assessment of other geothermal resources. The program is most useful when evaluating a large population of geothermal sites to identify superior ones.

The method is computerized on an MS-DOS based system and is a fast and reliable method of evaluating geothermal sites on a comparative basis. Error checking routines and a simple input-output framework helps with 'user friendliness.' There are two versions, for both high and low temperature geothermal resources. Together they form a useful tool for identification of superior geothermal sites for electricity production or district heating capability. Given availability of the site data, a site can be ranked in less than five minutes.

In the following appendices to the GEORANK program, instructions are provided for use of the program and a guide to a consistent evaluation of uncertainty values for the resource module are included.

## LOW TEMPERATURE UNCERTAINTY GUIDELINES

1.	Known Temperature of Fluids	
1.	Known	.9
2.	Estimated Drilling Depth	
1.	Drilled to Reservoir	.9
2.	Shallow drilling/inferred from Gradient	.6
3.	Inferred from similar Geologic areas	.5
4.	No data	.2
3.	Preferred Geothermometer Temperature	
1.	Calculated in Appendix II Resource Characterizations.	
4.	Total Flow Rate	
1.	Know- Well	.8
2.	Know- Artesian Spring	.7
3.	Unknown	.2
5.	Drilling Difficulty	
1.	Drilled	.9
2.	Inferred from similar Geologic Provinces	.7
6.	Prospect Areal Extent	
1.	Use the reservoir area Appendix II. If this is not available, then use the standard deviation of the reservoir volume divided by the reservoir volume as a proxy for the certainty level.	
7.	Local Gradient	
1.	Measured	.9
2.	Inferred or no data	.3
8.	Pumping Depth	
1.	Pump Test	.9
2.	Inferred	.5
3.	Unknown	.1

## HOW TO USE THE GEORANK PROGRAM

1. Once the computer is turned on with program disk in the disk drive, the monitor display will indicate that the program is being loaded into memory.
2. The program will announce when it is ready. Press the return key to go to the first question.
3. When each screen is displayed, the user will be prompted with a question. For each question, a default value will be displayed. If you like the default, or you do not know the correct answer for the question, then simply press the return key. If you would like to change the answer, then enter the numbers that you would like to enter. Enter no commas in the inputs and remember that all measures are given in SI (metric) units.
4. If you would like a printed copy of the results, then enter yes (1) for that question. Make sure that the printer is connected in slot 1 and the power is turned on.
5. There are some 25 questions in all, with equal numbers dealing with resource, market and environmental/institutional factors. If you are interested in only one category, then accept the defaults for the other questions. If you hold down the return key, questions will be assigned the defaults in succession.
6. After all the inputs have been entered, the program will display the modified scores for each characteristic and the summed total for the resource. A perfect score is 130. This number is followed by the most likely uncertainty and the most likely minimum score which is used for ranking purposes. Compare this number to that for another resource to determine the site with the greatest development potential.
7. Remember, this analytic procedure is only as good as the accuracy of the inputs. Only carefully researched data will ensure consistent and significant results using this research tool.

# LOW TEMPERATURE RESOURCE RANKING DATA

Site \_\_\_\_\_

Location \_\_\_\_\_  
 (Town) (County) (State)

	<u>Estimate</u>	<u>Certainty Level</u> 0-1
<b>I. <u>Resource</u></b>		
1. Known Temperature of Fluids	_____ C°	_____
2. Estimated Drilling Depth	_____ km	_____
3. Preferred Geothermometer Temp	_____ C°	_____
4. Total Flow Rate	_____ L/sec.	_____
5. Drilling Difficulty	_____ 1,2,3, or 4	_____
6. Prospect Area Extent	_____ km <sup>2</sup>	_____
7. Local Gradient	_____ C°/km	_____
8. Pumping Depth	_____ m	_____
<b>II. <u>Market</u></b>		
9. Distance to Heating Load	_____ km	
10. Resource Site Accessibility	_____ 1,2,3	
11. Trenchability of Pipeline Corridor	_____ 1,2,	
12. Terrain of Pipeline Corridor	_____ 0,1,2,3	
13. Annual Heating Load	_____ 10 <sup>9</sup> Btu	
14. Heat Load Density	_____ 1,2,3	
15. Least Cost Heat Energy	_____ \$/10 <sup>6</sup> Btu	
16. Heating Degree Days	_____ 65°F Base	
<b>III. <u>Regulatory/Environmental</u></b>		
17. Land/Resource Management	_____ 1,2,3	
18. Special Regulatory/Environmental Concerns	_____ 0,1,2,3,4	
19. Distance to Legally Designated Areas	_____ km	
20. Air/Water Pollutants	_____ 0-4+	
21. Owner Attitude Toward Development	_____ 1,2	

## Instructions for Low Temperature Resource Ranking Data Summary

General: Print or type all entries on the Resource Ranking Data Worksheet. Be sure to specify completely the site and its location. For all estimates and certainty levels, enter only numbers. Take care to observe the correct units.

Characteristic: The correct units are indicated. Where units are not specified in the estimate column you will find integers (1,2,3). In such cases enter one of the given numbers.

Certainty Level: Enter only a decimal value between 0 and 1 in the certainty level column for each resource characteristic. The certainty levels should come from the resource assessment sheets for that particular site. Enclosed are certainty estimate guidelines.

### I. RESOURCE:

1. Known Temperature of Fluids Enter the known temperature of fluids in degrees centigrade.
2. Estimated Drilling Depth Fill in the estimated drilling depth in kilometers. If there is no data then enter .2 km. for springs and .5 km for blind resources and enter a certainty level of 0.1.
3. Preferred Geothermal Temp Enter the preferred geothermometer temperature in degrees centigrade.
4. Total Flow Rate Units for total flow rate are liters per second. Expected range of entries is 0-35. Enter the maximum flow of the best well. If detailed information isn't available enter the aggregate flow.
5. Drilling Difficulty Rock competence is scored with a 1,2,3 or 4. See the table below for correct entry.

<u>Rock Competence</u>	<u>Entry</u>
Unconsolidated Rocks	1
Incompetent, Pliocene and Younger Volcanics	2
Miocene and Older Volcanics, Lithified Sandstone, Clastics	3
Crystalline Rocks	4

6. Prospect Areal Extent Enter the estimated resource prospect areal extent in square kilometers.
7. Local Gradient Units of gradient are degrees centigrade per kilometer of depth. Possible entries are 25-100.
8. Pumping Depth Enter the estimate including a 15 meter drawdown and safety factor. In absence of any data assume a 500 meter pump depth and a 0.1 certainty level. If the site is artesian enter a 0 for pumping depth.

## II. MARKET

9. Distance to Heating Load Value for distance to heating load should be entered in kilometers. It should be from 0-30 kilometers.
10. Resource Site Accessibility The values to be entered for site accessibility are 1,2, or 3. Roadless conditions are indicated by 1; unimproved roads by 2; and improved roads by 3.
11. Trenchability of Pipeline Corridor Enter a 1 for hard rock, and a 2 for soft or unconsolidated.
12. Terrain of Pipeline Corridor The entry for this characteristic ranges from zero to 3 representing the number of powerline concerns. Areas of concern are: 1) Terrain: Slope >30%; 2) Limited access; 3) Federal lands; 4) Agricultural lands; 5) Rivers/wetlands; 6) Recreational lands.
13. Annual Heating Load Enter the estimated value for annual heating load. Units are in  $10^9$  BTU. Range of expected entries is 0-2000.
14. Heat Load Density Enter a 1 for urban; 2 for suburban; 3 for rural areas. Use most populous area within 30 km. Rural is defined by populations less than 1,000; suburban is less than 50,000 but greater than 1,000; urban is greater than 50,000.
15. Least Cost Heat Energy Units are in dollars per  $10^6$  BTU. Enter a value from 0 to 20. In the case of fossil fuel resources, the LCHE should assume a 70% conversion efficiency (multiply cost/ $10^6$  BTU X 1.43).
16. Heating Degree Days This characteristic assumes a base of 65°F. Enter values from 4000 to 8000.

## III. REGULATORY/ENVIRONMENTAL

17. Land/Resource Management Enter a 1 for mixed ownership, 2 for federal, or local state, 3 for private land.
18. Special Regulatory/Environmental Concerns The values to be entered represent the number of special regulations or environmental concerns. Enter 0 for no concerns; 1,2,3,4 etc.
19. Distance to Legally Designated Areas The distance to designated area should be given in kilometers (0-5 km).
20. Air/Water Concerns This characteristic represents the number of air/water pollutants which are above EPA regulations. Enter 0,1,2,3,4+. See attached table for EPA levels above which substances become a concern.
21. Owner Attitude Toward Development To indicate a positive attitude enter 1; for a negative attitude enter 2.

ENVIRONMENTALLY HAZARDOUS SUBSTANCES

<u>Substance</u>	<u>Standard (ppm)</u>
Barium	1.00
Boron	5.00
H <sub>2</sub> S	0.05*
Rn	10,000 pc.
As	0.05
Hg	0.002
Fluoride	2.4
Silver	0.05
Selenium	0.01
T.D.S.	2000.00
Sulfates	250.00
Cadmium	0.01
Lead	0.05
Zinc	5.00
Iron	0.30
Copper	1.00
Chromium	0.05

All fluids are assumed to be injected back into the reservoir.

The above values are based on risk of drinking water contamination by surface filtration or subsurface injection. The total dissolved solids figure are based on the level above which mitigation measures are needed to prevent equipment problems.

\* Air Quality Standard

# DIRECT UTILIZATION RESOURCE RANKING DATA (DEFAULT VALUES)

SITE: default  
def1 COUNTY, defsta

CHARACTERISTIC	POINTS	UC^2
----------------	--------	------

## RESOURCE

1) FLUIDS-TEMP.	1.74	0.76
2) DRILLING DEPTH	0.51	07.02
3) GEOTHERM.TEMP.	1.45	0.53
4) FLOWRATE	5.19	6.72
5) DRILLING DIFF.	1.50	0.56
6) AREA EXTENT	4.00	4.00
7) LOCAL GRADIENT	0.36	0.03
8) PUMPING DEPTH	5.00	6.25

SUBTOTAL	19.75	
----------	-------	--

## ENGINEERING

9) HEAT-LOAD-DIST.	6.67	
10) SITE ACCESS	2.00	
11) TRENCHABILITY	2.00	
12) TERRAIN	1.32	
13) ANN.LOAD DENSITY	0.06	
14) LEAST ENERGY	0.19	
15) HEATING D.DAYS	00.00	

SUBTOTAL	12.24	
----------	-------	--

## REGULATORY/ENVIRON.

16) LAND/RESOURCE-MGN.	2.80	
17) SPECIAL REG./ENV.	9.00	
18) DIST.LEG.AREAS	2.96	
19) AIR/WATER	3.75	
20) OWNER ATTITUDE	00.00	

SUBTOTAL	18.51	
----------	-------	--

TOTAL	50.50	18.92
-------	-------	-------

SQRT UC^2= 4.35

MOST LIKELY SCORE	50.50
PROBABLE UNCERTAINTY	4.35
LIKELY MINIMUM SCORE	46.15

NORMALIZED MINIMUM SCORE	.355
--------------------------	------

# DIRECT UTILIZATION RESOURCE INPUT DATA (DEFAULT VALUES)

SITE: default  
def1 COUNTY, defsta

CHARACTERISTICS	EST.	CERTAINTY
=====		

## RESOURCE

1) FLUIDS-TEMP.	30.00 C	0.50
2) DRILL.DEPTH	2.00 KM	0.50
3) GEOTHERM.TEMP.	50.00 C	0.50
4) FLOWRATE	20.00 L/S	0.50
5) DRILLING DIFF.	3.00	0.50
6) AREA EXTENT	4.00 KM^2	0.50
7) LOCAL GRAD.	30.00 C/KM	0.50
8) PUMP.DEPTH	20.00 M	0.50

## ENGINEERING

9) LOAD DIST.	5.00 KM
10) SITE ACCESS	3.00
11) TRENCHABILITY	2.00
12) TERRAIN	1.00
13) AN.LD.DENSITY	20.00 10^9 BTU/YR
14) LEAST ENERGY	00.00 \$/10^6 BTU
15) H.D.D.	00.00 65 F.BASE

## REGULATORY/ENVIRON.

16) LAND/RSRC-MGN.	1.00
17) SPEC.REG./ENV.	1.00
18) DIST.LEG.AREAS	5.00 KM
19) AIR/WATER	1.00
20) OWNER ATTITUDE	2.00

=====

## DIRECT UTILIZATION (LOW TEMPERATURE) SITE RANKING: IDAHO

<u>Rank</u>	<u>Site</u>	<u>Normalized Minimum Score</u>
1.	Boise	.757
2.	Pocatello	.638
3.	Garden City	.627
4.	Ketchum	.607
5.	Fairfield	.592
6.	Butte City	.590
7.	Cascade	.587
8.	Chubbuck	.585
9.	Grand View	.583
10.	Twin Falls	.575
11.	Rexburg	.574
12.	American Falls	.573
13.	Nampa	.567
14.	Challis	.559
15.	Caldwell	.549
16.	Mountain Home	.548
17.	Council	.544
18.	Ashton	.541
19.	Mountain Home AFB	.541
20.	Midvale	.540
21.	Weiser	.539
22.	Idaho City	.538
23.	Buhl	.535
24.	Payette	.532
25.	Homedale	.531
26.	Glenns Ferry	.525
27.	Hansen	.524
28.	Filer	.523
29.	Lava Hot Springs	.522
30.	Emmett	.520
31.	Parma	.519
32.	Kimberly	.519
33.	Paul	.509
34.	Idaho Falls	.501
35.	Melba	.501
36.	Malad City	.491
37.	Kuna	.490
38.	Hailey	.486
39.	Ammon	.484
40.	Eagle	.482
41.	Meridian	.479
42.	Stanley	.479
43.	Soda Springs	.472

## DIRECT UTILIZATION (LOW TEMPERATURE) SITE RANKING: MONTANA

<u>Rank</u>	<u>Site</u>	<u>Normalized Minimum Score</u>
1.	Bozeman	.623
2.	Warm Springs State Hospital	.562
3.	White Sulphur Springs	.560
4.	Alhambra Hot Springs	.558
5.	Pipestone 1 & 2	.538
6.	Campaqua	.532
7.	Elkhorn Hot Springs	.531
8.	Camas	.529
9.	Medicine	.526
10.	Sleeping Child	.522
11.	Ananconda Hot Springs	.512
12.	Deer Lodge Warm Springs	.499
13.	Bedford	.497
14.	Wendt Well	.495
15.	Lolo Hot Springs	.494
16.	Chico	.492
17.	Avon Warm Springs	.492
18.	Carters Bride	.480
19.	Bridge Canyon	.468
20.	Greyson Spring	.462
21.	Corwin Hot Springs	.453
22.	Toston	.449
23.	Gallooly	.448
24.	Garrison Warm Springs	.445
25.	Bear Creek Springs	.441
26.	Baker's Hole	.434
27.	Renova	.433
28.	Quinn's	.410

## DIRECT UTILIZATION (LOW TEMPERATURE) SITE RANKING: OREGON

<u>Rank</u>	<u>Site</u>	<u>Normalized Minimum Score</u>
1.	Klamath Falls	.784
2.	Paisley	.695
3.	Union	.691
4.	Lakeview	.657
5.	Burns/Hines	.652
6.	La Grande	.630
7.	Imbler	.608
8.	Vale	.605
9.	Haines	.601
10.	Adrain	.597
11.	Pendleton	.593
12.	Spray	.592
13.	Stanfield	.579
14.	Pilot Rock	.579
15.	Boardman	.575
16.	Weston	.574
17.	Athena	.573
18.	Umatilla	.566
19.	Hermiston	.566
20.	Echo	.564
21.	Kahneeta	.564
22.	Ontario	.556
23.	Heppner	.553
24.	Ashland	.553
25.	Baker	.551
26.	Irrigon	.548
27.	Cove	.544
28.	Parkdale	.543
29.	Arlington	.543
30.	Huntington	.542
31.	Rajneeshpuram	.541
32.	Government Camp	.538
33.	Milton Freewater	.537
34.	The Dalles	.537
35.	Lexington	.533
36.	Jordan Valley	.522
37.	Oakridge	.499
38.	Troutdale	.468
39.	Ritter HS	.459
40.	North Powder	.444

## DIRECT UTILIZATION (LOW TEMPERATURE) SITE RANKING: WASHINGTON

<u>Rank</u>	<u>Site</u>	<u>Normalized Minimum Score</u>
1.	Yakima	.703
2.	Pullman	.625
3.	St. Martin's Hot Springs	.606
4.	Richland	.599
5.	Pasco	.595
6.	Wahkiacus	.586
7.	Kennewick	.575
8.	Ellensburg	.574
9.	Walla Walla	.565
10.	Othello	.549
11.	North Bonneville	.543
12.	College Place	.541
13.	Davenport	.539
14.	Mabton	.538
15.	Cheney	.536
16.	Harrah	.533
17.	Grandview	.533
18.	West Richland	.532
19.	Soap Lake	.531
20.	Pomeroy	.529
21.	Lind	.526
22.	Zillah	.522
23.	Stevenson	.521
24.	Ritzville	.519
25.	Colfax	.518
26.	Washtucha	.516
27.	Moses Lake	.508
28.	Ephrata	.505
29.	Wenatchee	.502
30.	Toppenish	.502
31.	Sunnyside	.502
32.	Granger	.501
33.	Clarkson	.492
34.	Odessa	.492
35.	Benton City	.467
36.	Connell-Cunningham	.466
37.	Warden	.461
38.	Prosser	.455
39.	East Wenatchee	.451





## APPENDIX 10

### Life Cycle Cost Analysis Computer Program

- o Life Cycle Cost Analysis Program Summary
- o Life Cycle Cost Analysis Program Listing



## COMMENTS ABOUT THE SYSTEM

In general, the user alters variables in the input/output section of the spreadsheet (b1..f30). Apparently, the only major output of concern is the leveled cost. By altering the values in this area, recalculating, and watching the results, the user can analyze the cost effectiveness of the project.

The work area is a calculation area used to derive the leveled cost value mentioned above. In the work area, several columns are used. The columns use repeating formulas. This version varies slightly from the original. In this version, I made a column of numbers, 1 - 50, starting at AA1. Thus, AA1 contains the number 1, AA2 = 2, AA3 = 3, and so on. The original program had integer values incrementing for each year used in the calculations. Rather than code each formula in by hand, I reference the AA? cell as a relative address. Thus, I can copy an entire column of formulas without having to enter the integer values.

An example of this can be seen in the range b42..b73. The last factor of the formula in cell b42 is 7; in b43, 8; in b44, 9; and so on. As the program was originally written, the values were hardcoded for each cell. In this version, however, I reference the AA? column of integers as a relative address, and copy the first formula to the bottom of the column.

Because the spreadsheet is quite small and the columns are clearly labeled, no further explanation should be needed to understand the spreadsheet.



## Life Cycle Cost Analysis Program

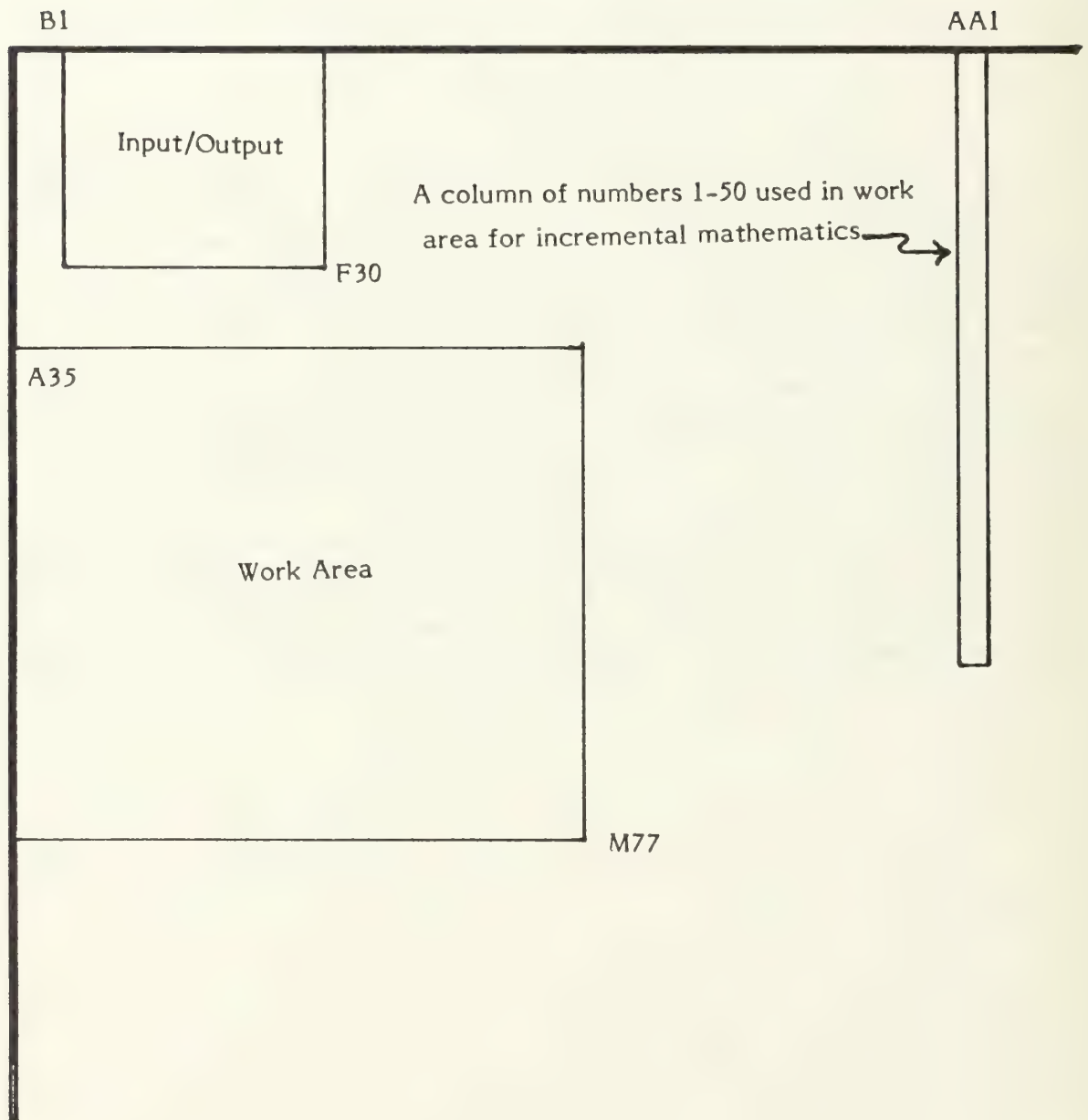
The energy analysis program is used to analyze the financial aspects of energy projects. It was originally written by Dan Parker, currently with the Northwest Power Planning Council in Montana. The program was written on an Apple computer using the Appleworks spreadsheet system. This version of the program is a direct translation of the Appleworks version to a Lotus spreadsheet using a COMPAQ computer (with MS.DOS 2.0 operating system).

This document is designed to help a programmer understand the spreadsheet. It is not designed to help a user apply the program to energy projects. It contains a spreadsheet map, a list of cell formulas for the spreadsheet, and sample output.

To run the program, load the program disk into drive b of your computer. If you are using a harddisk system, first copy the program onto the harddisk. The program to copy is titled ECBPA.WKS. When the program is loaded into the system, then boot up Lotus and retrieve the file ECBPA. From this point on you are on your own.

# Life Cycle Cost Analysis

## SPREADSHEET MAP



Life Cycle  
Cost Analysis  
Computer  
Program  
Listing



# CELL FORMULAS FOR THE INPUT/OUTPUT AREA

=====

B1: 'B.P.A. COST METHODOLOGY FOR RESOURCE ASSESSMENT

B2: 'ASSUMPTIONS:

B3: '-----

C3: '-----

D3: '-----

E3: '-----

B4: 'REAL DISCOUNT RATE

C4: 3

D4: '%

E4: 'SINGLE/DBL FLASH

B5: 'FINANCE RATE

C5: 13

D5: '%

E5: 'LEVELIZED COST MODEL

B6: 'FIXED COST/KW

C6: 50

D6: '\$

E6: '20% CAPITAL COST CONTINGENCY

B7: 'CAPITAL COST/KW

C7: 3474.23

D7: '\$

B8: 'REPLACEMENT WELL COST

C8: 2000000

D8: '\$

B9: 'O&M ESCALATION RATE

C9: 1.3

D9: '%

B10: 'PLANT SIZE (MW)

C10: 50

D10: 'MW

E10: 'LEVELIZED COST

B11: 'VARIABLE O&M COSTS

C11: 0

D11: '\$

E11: (F2) +M77\*1000

B12: 'PHYSICAL LIFE

C12: 30

D12: 'YEARS

E12: 'MILLS/KWH

B13: 'CONSTRUCTION COST/YR 1

C13: 20

D13: '%

B14: 'CONSTRUCTION COST/YR 2

C14: 30

D14: '%

B15: 'CONSTRUCTION COST/YR 3

C15: 50

D15: '%

B16: 'CAPACITY FACTOR

C16: 80

D16: '%'  
 B17: 'INFLATION RATE  
 C17: 6  
 D17: '%'  
 B18: 'YEAR ON LINE  
 C18: 1990  
 B19: 'ANNUAL ELECTRICITY  
 C19: +C10\*C16/100\*1000\*8760  
 D19: 'KWH  
 B20: 'TOT. PLANT CAPITAL COST  
 C20: +C7\*C10\*1000  
 D20: '\$  
 B21: 'VARIABLE COST  
 C21: +C11\*C19  
 D21: '\$  
 B22: 'FIXED COST  
 C22: 2440000  
 D22: '\$  
 B23: 'ANNUAL TOT. O&M COST  
 C23: +C21+C22  
 D23: '\$  
 B24: 'CAPITAL RECOVERY FACTOR  
 C24: (F4) (C5/100)/(1-((1/(1+(C5/100)))^C12))  
 B25: 'DISCOUNT CRF  
 C25: (F4) (C4/100)/(1-((1/(1+(C4/100)))^C12))  
 B26: '-----

B27: ^CONSTRUCTION COSTS  
 C27: ^INTEREST  
 D27: ^YEAR  
 B28: (C0) +\$C\$20\*(C13/100)\*(((1+(\$C\$17/100))\*(1+ \$C\$9/100)))^AA4)  
 C28: (C0) +B28\*(((1+(\$C\$5/100))^2.5)-1)  
 D28: 1987  
 B29: (C0) +\$C\$20\*(C14/100)\*(((1+(\$C\$17/100))\*(1+(\$C\$9/100)))^AA5)  
 C29: (C0) +B29\*(((1+(\$C\$5/100))^1.5)-1)  
 D29: 1988  
 B30: (C0) +\$C\$20\*(C15/100)\*(((1+(\$C\$17/100))\*(1+(\$C\$9/100)))^AA6)  
 C30: (C0) +B30\*(((1+(\$C\$5/100))^0.5)-1)  
 D30: 1989

# CELL FORMULAS FOR THE WORK AREA

=====

This is the cell formula pattern for the A column of the worksheet.

```
A38: '-----
A39: 1987
A40: +A39+1
A41: +A40+1
A42: +A41+1
A43: +A42+1
A44: +A43+1
A45: +A44+1
A46: +A45+1
A47: +A46+1
A48: +A47+1
A49: +A48+1
      :
      :
A73: +A72+1
A74: '-----
```

This is the cell formula pattern for the B column of the worksheet.

```
B36: ^NOMINAL CONSTANT
B37: ^O&M COSTS
B38: '-----
B39: ^CONSTRUCTION YR1
B40: ^CONSTRUCTION YR2
B41: ^CONSTRUCTION YR3
B42: ($C$23*((1+($C$17/100))*(1+($C$9/100)))^AA7)
B43: +$C$23*((1+($C$17/100))*(1+($C$9/100)))^AA8)
B44: +$C$23*((1+($C$17/100))*(1+($C$9/100)))^AA9)
B45: +$C$23*((1+($C$17/100))*(1+($C$9/100)))^AA10)
B46: +$C$23*((1+($C$17/100))*(1+($C$9/100)))^AA11)
B47: +$C$23*((1+($C$17/100))*(1+($C$9/100)))^AA12)
B48: +$C$23*((1+($C$17/100))*(1+($C$9/100)))^AA13)
B49: +$C$23*((1+($C$17/100))*(1+($C$9/100)))^AA14)
      :
      :
B73: +$C$23*((1+($C$17/100))*(1+($C$9/100)))^AA38)
B74: '-----
```

This is the cell formula pattern for the D column  
of the worksheet.

```
D36: ^PERIODIC
D37: ^O&M COSTS
D38: '-----
D42: +$C$8*(((1+($C$17/100))*(1+($C$9/100)))^AA7)
D43: +$C$8*(((1+($C$17/100))*(1+($C$9/100)))^AA8)
D44: +$C$8*(((1+($C$17/100))*(1+($C$9/100)))^AA9)
D45: +$C$8*(((1+($C$17/100))*(1+($C$9/100)))^AA10)
D46: +$C$8*(((1+($C$17/100))*(1+($C$9/100)))^AA11)
D47: +$C$8*(((1+($C$17/100))*(1+($C$9/100)))^AA12)
D48: +$C$8*(((1+($C$17/100))*(1+($C$9/100)))^AA13)
D49: +$C$8*(((1+($C$17/100))*(1+($C$9/100)))^AA14)
      :
      :
D73: +$C$8*(((1+($C$17/100))*(1+($C$9/100)))^AA3B)
D74: '-----
```

This is the cell formula pattern for the G column  
of the worksheet.

```
G36: ^MORTGAGE
G37: ^PAYMENT
G38: '-----
G42: (B28+B29+B30+C28+C29+C30)*C24
G43: +G42
G44: +G43
G45: +G44
G46: +G45
G47: +G46
G48: +G47
G49: +G48
      :
      :
G73: +G72
G74: '-----
```

This is the cell formula pattern for the I column  
of the worksheet.

```
I36: 'TOTAL NOMINAL
I37: 'COST STREAM
I38: '-----
I42: +B42+G42+D42
I43: +B43+G43
I44: +B44+G44
I45: +B45+G45+D45
I46: +B46+G46
I47: +B47+G47
I48: +B48+G48+D48
I49: +B49+G49
I50: +B50+G50
I51: +B51+G51+D51
I52: +B52+G52
I53: +B53+G53
I54: +B54+G54+D54
I55: +B55+G55
I56: +B56+G56
I57: +B57+G57+(D47*2)
I58: +B58+G58
I59: +B59+G59
I60: +B60+G60+D60
I61: +B61+G61
I62: +B62+G62
I63: +B63+G63+D63
I64: +B64+G64
I65: +B65+G65
I66: +B66+G66+D66
I67: +B67+G67
I68: +B68+G68
I69: +B69+G69+D69
I70: +B70+G70
I71: +B71+G71
I72: +B72+G72
I73: +B73+G73
I74: '-----
```

This is the cell formula pattern for the K column of the worksheet.

```
K36: 'CONSTANT
K37: 'DOLLARS
K38: '-----
K42: +I42*(1/((1+($C$17/100))^AA7))
K43: +I43*(1/((1+($C$17/100))^AA8))
K44: +I44*(1/((1+($C$17/100))^AA9))
K45: +I45*(1/((1+($C$17/100))^AA10))
K46: +I46*(1/((1+($C$17/100))^AA11))
K47: +I47*(1/((1+($C$17/100))^AA12))
K48: +I48*(1/((1+($C$17/100))^AA13))
K49: +I49*(1/((1+($C$17/100))^AA14))
:
:
K73: +I73*(1/((1+($C$17/100))^AA38))
K74: '-----
```

This is the cell formula pattern for the M column of the worksheet.

```
M36: 'PRESENT VALUE
M37: 'COST STREAM
M38: '-----
M42: +K42/((1+($C$4/100))^AA1)
M43: +K43/((1+($C$4/100))^AA2)
M44: +K44/((1+($C$4/100))^AA3)
M45: +K45/((1+($C$4/100))^AA4)
M46: +K46/((1+($C$4/100))^AA5)
M47: +K47/((1+($C$4/100))^AA6)
M48: +K48/((1+($C$4/100))^AA7)
M49: +K49/((1+($C$4/100))^AAB)
:
:
M73: +K73/((1+($C$4/100))^AA32)
M74: '-----
```

These are the cell formulas for the summary section at the bottom of column M. Range: J76..M77

```
J76: 'TOTAL PRESENT VALUE:
M76: @SUM(M41..M73)
J77: 'LEVELIZED COST:
M77: (C25*M76)/C19
```

This is a sample of the input/output area.  
 Range: B1..E30

B.P.A. COST METHODOLOGY FOR RESOURCE ASSESSMENT  
 ASSUMPTIONS:

REAL DISCOUNT RATE	3 %	SINGLE/DBL FL
FINANCE RATE	13 %	LEVELIZED COS
FIXED COST/KW	50 \$	20% CAPITAL C
CAPITAL COST/KW	3474.23 \$	
REPLACEMENT WELL COST	2000000 \$	
O&M ESCALATION RATE	1.3 %	
PLANT SIZE (MW)	50 MW	LEVELIZED COS
VARIABLE O&M COSTS	0 \$	53.10
PHYSICAL LIFE	30 YEARS	MILLS/KWH
CONSTRUCTION COST/YR 1	20 %	
CONSTRUCTION COST/YR 2	30 %	
CONSTRUCTION COST/YR 3	50 %	
CAPACITY FACTOR	80 %	
INFLATION RATE	6 %	
YEAR ON LINE	1990	
ANNUAL ELECTRICITY	350400000 KWH	
TOT. PLANT CAPITAL COST	173711500 \$	
VARIABLE COST	0 \$	
FIXED COST	2440000 \$	
ANNUAL TOT. O&M COST	2440000 \$	
CAPITAL RECOVERY FACTOR	0.1334	
DISCOUNT CRF	0.0510	

CONSTRUCTION COSTS	INTEREST	YEAR
\$46,187,006	\$16,505,542	1987
\$74,392,025	\$14,968,157	1988
\$133,134,447	\$8,389,411	1989

This is a sample of the work area.  
 Range: A36..F75

	NOMINAL CONSTANT O&M COSTS		PERIODIC O&M COSTS
1987	CONSTRUCTION YR1	---->	
1988	CONSTRUCTION YR2	---->	
1989	CONSTRUCTION YR3	---->	
1990	4016030.4842		3291828.265
1991	4312333.2133		3534699.355
1992	4630497.1578		3795489.473
1993	4972135.2381		4075520.686
1994	5338979.3759		4376212.603
1995	5732889.2743		4699089.569
1996	6155861.8449		5045788.397
1997	6610041.3319		5418066.665
1998	7097730.1813		5817811.624
:	:		:
:	:		:
2021	36489812.358		29909682.26

This is a sample of the work area.  
Range: G36..M78

MORTGAGE PAYMENT	TOTAL NOMINAL COST STREAM	CONSTANT DOLLARS	PRESENT VALUE COST STREAM
---------------------	------------------------------	---------------------	------------------------------

39166243	46474102	30907932	30007701
39166243	43478576	27278996	25713070
39166243	43796740	25923223	23723421
39166243	48213899	26922389	23920194
39166243	44505222	23444796	20223687
39166243	44899132	22313493	18687199
39166243	50367893	23614434	19200695
39166243	45776284	20246894	15983085
39166243	46263973	19304339	14795169
:	:	:	:
:	:	:	:
39166243	75656055	8264580.	3209442.

TOTAL PRESENT VALUE:	3.6E+08
LEVELIZED COST:	0.053096









